COMBUSTION

DEVOTED TO THE ADVANCEMENT OF STEAM PLANT DESIGN AND OPERATION

Vol. 9, No. 9 | MARCH, 1938 | 25c a copy

MAR 31 1938

Courtesy of Stone & Webster Engineering Corporation

Neches Power Station of the Gulf States Utilities Company

Neches Power Station Extension at Beaumont, Texas

Testing Steam Condensate for Its Quality and Purity

The Economics of Subsidized Power

A NEW WORLD'S RECORD for STEAM PLANT EFFICIENCY

★ Port Washington again lowers the mark with a 1937 average of 10,835 Btu. ★

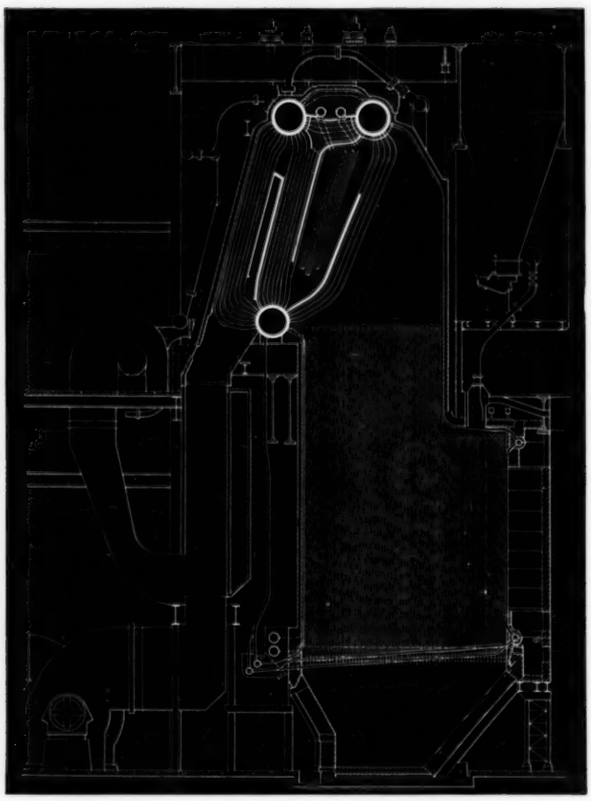
The Port Washington Station of The Milwaukee Electric Railway and Light Company, which comprises a single C-E Steam Generating Unit serving an 80,000 kw turbine-generator, went into regular operation in the latter part of 1935.

During 1936, its first full year of operation, this station showed an average heat consumption of 10,954 Btu per net kwhr which marked it as the most efficient steam station in the world. The 1937 performance bettered this notable record, the average heat consumption having been reduced to 10,835 Btu per net kwhr—a new world's record for steam plant efficiency.

For the entire period since the plant was placed in service to Dec. 26, 1937, it has been operated 86.2 per cent of the time. The distribution of plant outage is as follows: Scheduled Inspections—6.2 per cent, Lack of Load—2.5 per cent, Mechanical Trouble—2.2 per cent, Corrosion Trouble—2.9 per cent. The corrosion was determined to be of an electro-chemical nature and was eliminated in January 1937. The fact that Port Washington is not a base load station and that it is subject to a considerable load variation at times makes its record the more remarkable.

Combustion Engineering fully appreciates that a large portion of the credit for this performance record is attributable to the engineering ability and operating skill of those responsible for the station operation. We do feel, however, that here again we have convincing evidence that the confidence placed in the dependability and efficiency of C-E equipment, by those who have selected it for many of the most prominent steam generation projects of the last few years, has been amply justified.

Further recognition of the extra values obtainable in C-E equipment is found in the facts that C-E furnished the boilers last purchased for the world's largest public utility, industrial and central heating plants. Of the world's eight boilers having capacities of a million or more pounds of steam per hour, six are C-E Units.



C-E Steam Generating Unit installed at Port Washington Station. Designed to produce 690,000 lb of steam per hr at 1320 lb pressure and 830°F total temperature. C-E equipment includes Boiler, Front and Rear Water Walls, Air Heaters and Pulverized Fuel Burners, Mills and Feeders

Combustion Engineering Company, Inc.,
200 Madison Avenue New York, N. Y.
Canada
Combustion Engineering Corp. Ltd.—Montreal

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COMBUSTION ENGINEERING

ALL TYPES OF BOILERS, FURNACES, PULVERIZED FUEL SYSTEMS AND STOKERS, ALSO SUPERHEATERS, ECONOMIZERS AND AIR HEATERS

COMBUSTION

DEVOTED TO THE ADVANCEMENT OF STEAM PLANT DESIGN AND OPERATION

VOLUME NINE NUMBER NINE

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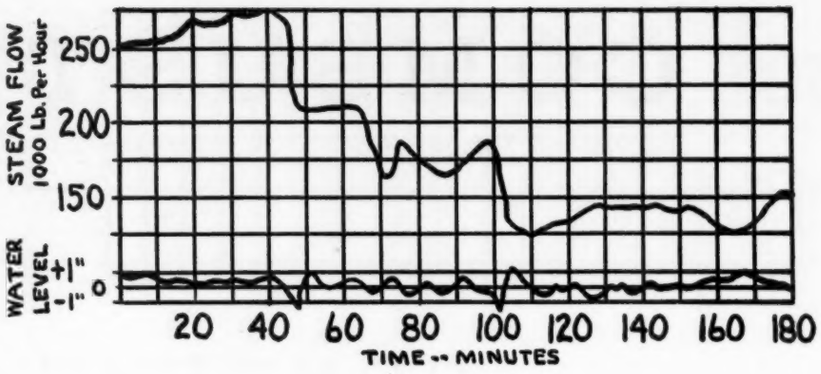
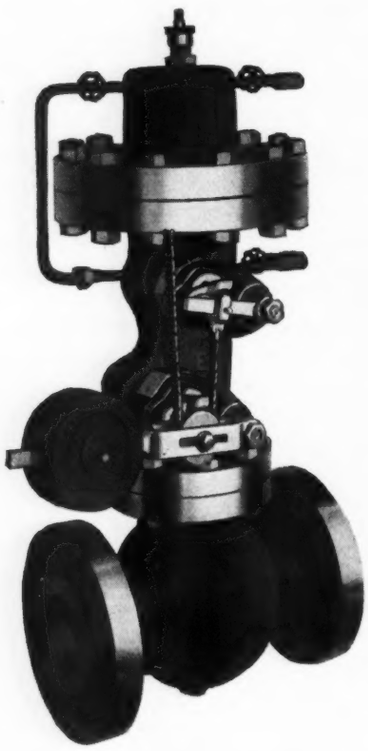


Charts prove value of steam-flow type COPES *feed water control*



Plant: prominent utility. Boiler: 800-pound pressure cross-drum. Firing: pulverized coal. Load: between 275,000 and 125,000 pounds per hour. Water level: held within plus or minus 1.5 inches. Feed water regulator: the new COPES Flowmatic, a simplified steam-flow type. Ideal for your high-pressure, high-rating boilers. Write for descriptive Bulletin 409-A.

NORTHERN EQUIPMENT CO., 316 GROVE DRIVE, ERIE, PA.
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Get closer boiler water level control with the new

COPES

FEEDS BOILER ACCORDING TO STEAM FLOW•AUTOMATICALLY

FLOWMATIC

★ REGULATOR

EDITORIAL

Coal Commission Starts Anew

The price structure and marketing rules as established last December by the National Bituminous Coal Commission have broken down as a result of numerous court actions instituted by municipalities, railroads, groups of industrial consumers and certain coal producers. In fact, these suits have been concurred in by the "Consumers' Counsel" a Federal agency created by the Guffey-Vinson Act to protect the interests of the consumer. As a result, the Commission has rescinded about half its orders, cancelled the esablished prices and will begin anew.

It is significant that these numerous court actions were based on technicalities and were directed not at the validity of the Bituminous Coal Act but at the procedure whereby the prices were established, it being claimed that in many cases prices were fixed more or less arbitrarily without adequate hearings as provided under the Act. The procedure under attack was brought about by the failure of various district boards to reach agreements last fall, as a result of which the Commission itself undertook to coordinate prices in an effort to get the Act functioning within the period it had prescribed.

In rescinding its orders and prices the Commission gave out, as the reason, its disinclination to contest the numerous court actions in view of the fact that during such a period of litigation those producers not directly affected by the restraining court orders would be compelled to operate at a disadvantage. This appears logical, but well-informed opinion also inclines to the belief that the Commission was encountering administrative difficulties and probably sensed the defects in the price structure it had set up; and that it therefore executed a clever move not only to nullify the court actions but to forestall the ultimate practical breakdown of the price pattern and permit making a fresh start. While these prices had been in force hardly long enough to form the basis of definite conclusions, many inequalities were apparent and they had the effect of moving the better-grade coals to the detriment of poorer grades, the greater movement of which at higher prices was one of the underlying objectives of the Bituminous Coal Act. Since the Commission's action, the market prices of these poorer grades have fallen off sharply.

Because of the innumerable types and characteristics of coal mined in this country and the complex marketing situation, it is a herculean task to attempt to stabilize the coal industry, but it is an even greater task to satisfy the buying public when such regimentation results in substantially higher prices unless such prices can be justified in the eyes of the consumer.

Regardless of individual opinions as to the provisions of the Bituminous Coal Act of 1937, it is now the law and would probably be sustained by the Supreme Court as at present constituted. Future successful administration of the Act will depend largely upon securing the complete confidence of the public. How well the Commission will succeed in its second effort remains to be seen. If it takes the consuming public into its confidence by holding open hearings on classifications of coals and on regulations as well as on prices, and the resulting price pattern is valid, few serious objections are likely to be encountered.

Progress by Cooperation

Those identified with the power plant field twenty years ago will recall a prevailing disposition on the part of both manufacturers and users at that time to soft-pedal all public references to operating difficulties and often to performance, as well. That this situation has now changed to a marked extent may be inferred from the numerous recent discussions before engineering societies, in association reports and in current technical literature. The present attitude appears to be one of mutual helpfulness, through frank discussion, to the end that all may profit by one another's experiences. It also tends to forestall the circulation of misinformation or fragmentary information, occasionally magnified to serve selfish aims. This applies to both steam generating units and prime movers, as well as major auxiliaries.

During a period of such rapidly advancing practice as has obtained during the past three years, with innumerable new and varying conditions to be met, there was little opportunity to progress step by step and often it became necessary to incorporate several innovations in a single design. New conditions of operation brought forth unanticipated problems that could be solved only in the light of experience. It was inevitable, therefore, that some operating troubles should be encountered and, because of the many interdependent factors, immediate isolation of the cause was sometimes difficult. In general, designs which represented an evolution from well-tried practice presented difficulties of lesser magnitude than the more radical departures from conventional practice.

Unlike many other lines of manufacture, most power plant equipment is of such size or capacity as to preclude shop trials; hence the plant must become the laboratory in which new designs are tried out and adjustments made. Inasmuch as the conditions necessitating departures from conventional designs are prescribed by the user, he becomes, to a large extent, a partner in their development. He has as much at stake in their successful functioning as has the manufacturer and his cooperation to this purpose is to be expected. In most cases the difficulties that have been encountered are being readily remedied through such cooperation.

The present recession, despite its many adverse aspects, has provided an opportunity for the engineers to work out many problems involving design and operation to the end that they will be fortified by this experience when the rush of new work again descends upon the industry. In this connection the many public discussions of operating problems have been most helpful.

Neches Power Station Extension at Beaumont, Texas

A 320,000-lb per hr bent-tube boiler supplies steam at 850 lb, 900 F, to a 25,000-kw, 3600-rpm condensing turbine-generator, these steam conditions having been determined as giving the best overall results in view of the relatively low-priced fuel, the annual load factor and the required capital investment. This extension is laid out on the unit principle and its operation, on the steam end, will be independent of the existing low-pressure units. Natural gas will be burned, although provision is made for burning fuel oil, if desired. The expected heat consumption of the new units is under 13,000 Btu per net kilowatt-hour.

By MAURICE W. CARTY
Mechanical Engineer,
Stone & Webster Engineering Corp.

THE Neches Power Station at Beaumont, Texas, is the principal generating plant of the Gulf States Utilities Company which serves a large area in southeastern Texas, extending along the Gulf to Louisiana. This station, which was built some years ago, contained one 35,000-kw and one 25,000-kw turbine-generator supplied with steam at 360 lb gage and 700 F from four 180,000-lb, per hr boilers. A steady growth in system load and expected increases made additional generating capacity desirable, hence Stone & Webster Engineering Corporation was engaged to design and construct an extension to this station, to be available in the spring of 1938.

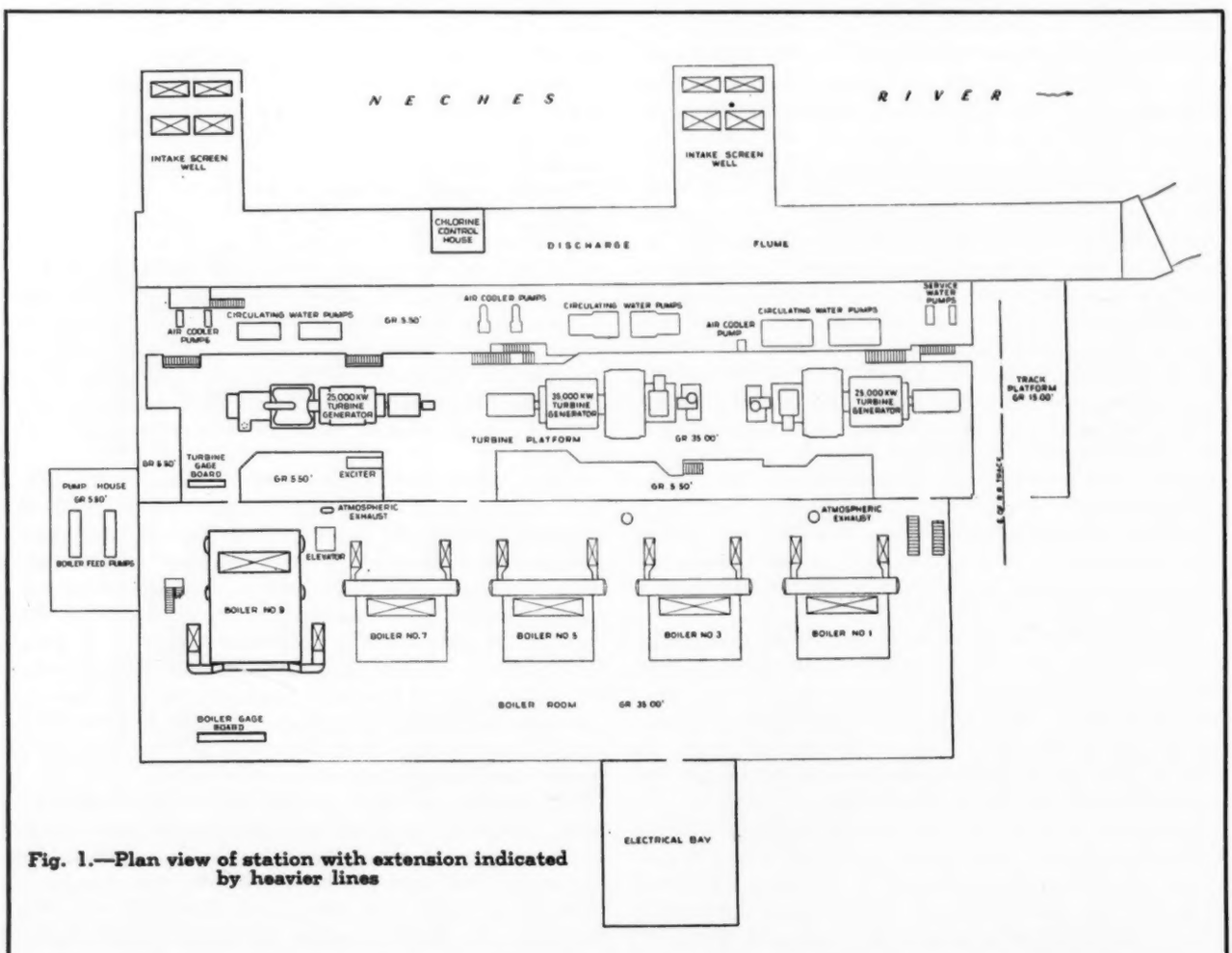


Fig. 1.—Plan view of station with extension indicated by heavier lines

As a result of the studies made, it was decided to install a 25,000-kw condensing unit and a single boiler of 320,000 lb per hr output. While this steam capacity is somewhat larger than necessary for the present turbine requirements, it is probably about the size of the next future steam generating unit. Steam conditions of 850 lb and 900 F total steam temperature were selected as giving the best overall results considering the fairly low priced fuel, the capital investment and the desirability of leaving the way open for a possible future "topping" unit, perhaps compounded with the present low-pressure turbines.

As will be seen from the plan view, the extension matches the earlier construction, although, because of the different steam conditions involved, the unit arrangement is followed and there is no cross-connection between the high-pressure piping and the lower pressure header. Also, the new unit has an independent condenser circulating water system. The new concrete stack, carried on the building steelwork, is lined its full height with brick. An electrical control house has been constructed as part of the present work to take care of the operation of the high-pressure turbine-generator as well as the older low-pressure units. In it are located the main control switchboard, step-up transformers and outgoing feeders, as well as the station instrument and the battery control boards. It also houses the office and a testing laboratory.

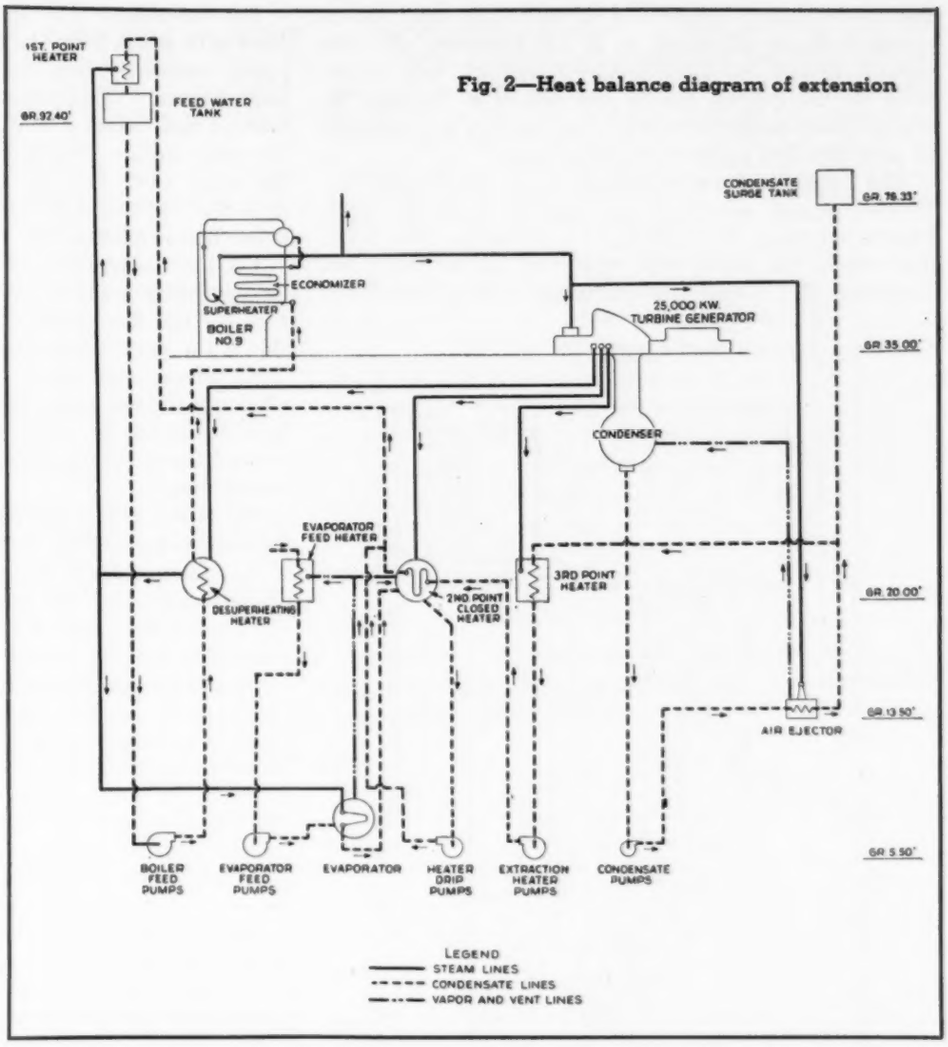


Fig. 2—Heat balance diagram of extension

Natural gas from nearby fields is ordinarily burned at this station but provision is made also for burning fuel oil, and a 2000-barrel storage tank has been built to supplement the earlier tanks.

The boiler, of 10,000 sq ft heating surface, is of the three-drum C-E bent-tube type with a convection superheater located in the second pass and a continuous-loop finned economizer below the rear drum, within the boiler casing. Two horizontal-shaft air heaters of the Ljungstrom regenerative type are located on the floor above the boiler. The furnace, of 14,850 cu ft, is completely surrounded by plain water-cooled tubes, the bottom screen tubes being covered with tile. The six burners are of the mechanical atomizing type and are designed to burn either natural gas or fuel oil. Within the 54-in. steam drum is located a bubble-type steam washer, and the feedwater treatment will consist of the addition of small amounts of caustic soda and phosphate. The boiler is designed for a steam pressure of 950 lb per sq in., or 875 lb at the superheater outlet. A Bailey full automatic combustion control operates at all loads when burning either natural gas or fuel oil, and superheat is controlled automatically by positioning dampers located in the upper part of the boiler to bypass a portion of the gases around the superheater when necessary.

The new turbine-generator is a 3-phase, 60-cycle, 13,800-volt, 3600-rpm Westinghouse unit with the two cylinders arranged in tandem and with a 2500-kw auxiliary generator and its exciter mounted on an extension to the shaft of the main unit. The turbine exhausts to a two-pass surface condenser, and an intermittent chlorine de-sliming system for the condenser circulating water is installed.

Heat Balance

The heat balance diagram for the new installation is shown in Fig. 2. The cycle utilizes steam from three extraction points of the turbine in a regenerative build-up of condensate temperature to about 375 F at full output. The third-point extraction heater receives steam at a pressure below atmosphere and is of the direct-contact type in which the steam intermingles with the water to impart its heat. The second-point heater, supplied by steam at higher pressure, is of the closed or tubular type in which heat is transmitted by conduction,

but the first-point heater is of the open type and utilizes steam at about 165 lb per sq in. abs pressure. Booster pumps, driven by variable-speed motors, take water from the third-point heater and deliver it through the second-point heater of tubular construction well adapted to pass this flow to the first-point heater.

The discharge head conditions of the main condenser hotwell pumps are moderate because it is necessary merely for them to discharge to the surge tank level. The use of the closed-type heater at the second point simplifies the condensate pumping system since only one set of booster pumps is required. Steam extracted from the first point is superheated, hence a desuperheating heater is placed in the steam flow to take out the superheat and raise the temperature of the condensate to a heat level perhaps 8 deg F higher than can be reached in the first-point heater where saturation temperature must exist. Condensate from the second-point extraction heater is pumped "upstream" into the pipe line beyond this heater and consequently is not degraded in temperature level.

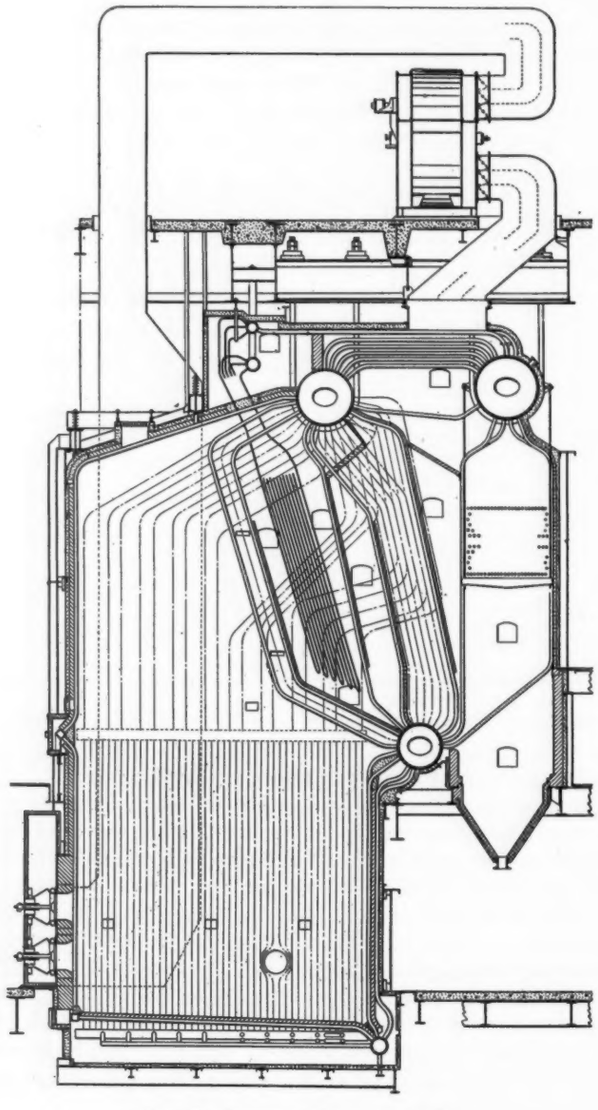


Fig. 3—Section through boiler

The evaporator for boiler feedwater makeup is supplied with steam from the first-point bleed, and its vapor passes ordinarily into the steam space of the second-point heater. The operation of the evaporator is intermittent and, when it is in service, the condensate from the main surface condenser hotwell pumps builds up in the surge tank floating on the system and overflows into the distilled-water storage tanks, located in the boiler house substructure.

The limit of temperature rise in the regenerative cycle for feedwater heating is fixed by the planned temperature for the flue gases leaving the economizer because this is the point where the water enters the boiler unit. This temperature level is set to obtain the desired efficiency in heat absorption, but so as to leave sufficient heat in the flue gases to prevent excessive condensation beyond the air heaters and minimize the corrosion of the smoke flue.

The steam pressures vary in the first-point extraction heater, corresponding to changes in load on the turbine, and it so happens that this results in satisfactory characteristics for the boiler feed pumps operating at constant speed. The water-level floats installed in the extraction heaters operate pilot valves, and compressed air is utilized as the positive force to position the controlled water valves. The condensate system is planned to give smooth flow at all loads, submerged operation of the pumps, and to avoid water hammer. Any back flow into the turbine extraction points is prevented and protection is provided against trouble from split heater tubes. Any heater unit can be bypassed, and makeup is added to the system by operating the evaporator, or by pumping in any quantity necessary from the distilled-water storage tank. If the motor-driven boiler feed pump fails, or if the condensate flow is interrupted for any reason, an emergency turbine-driven feed pump comes immediately into service.

The main turbine is provided with two openings well down in its lower stages and steam and moisture are drawn out by the condensing effect of tubular heaters. This lessens the abrasion by entrained water on the low-pressure turbine blading. The steam condensed in these heaters passes into the main condenser. An automatic bypass valve permits the recirculation of a portion of the discharge from the condenser hotwell pumps so that they are always supplied with sufficient water even under low load operation of the main turbine-generator.

The auxiliaries at the condenser floor level, including the boiler-feed extraction heater pumps and the distilled-water pumps, are under the eye of the operator there who is responsible for the service, and a gage board with suitable controls is in a convenient location at this level. The primary responsibility for the boiler operation rests with the operator at the firing aisle level, and a control board is also located there. Duplicate indicators and controls are provided so that the attendant at the boiler, if circumstances require, can take over the operation of these vital auxiliaries to maintain uninterrupted operation and to safeguard the boiler against low water.

The induced- and forced-draft fans and their motor drives are located in a room above the boiler, protected from the heat of the upper part of the boiler room. The forced-draft fan draws air from the boiler room in summer and can draw its supply from out-of-doors in winter

if desired. Also, because of the rapid and extreme climatic conditions at Beaumont, a complete ventilating and heating system is provided to prevent excessive temperatures in summer and to minimize condensation in winter, the latter condition being particularly objectionable in the electrical switch rooms.

Much of the piping is welded although field welds have been avoided in the high temperature steam lines. The materials of the latter were selected with reference to creep resistance.

At full load operation and with a satisfactory vacuum, the heat consumption of the new extension is expected to be under 13,000 Btu per net kilowatt-hour generated. This is believed to be in conformity with the economy justified by the price of fuel and the expected annual load factor.

Principal Equipment in Neches Power Station Extension

General

COMPANY—The Gulf States Utilities Company
LOCATION—Beaumont, Texas
SERVICE—Electric light and power
ENGINEERS AND CONSTRUCTORS—*Stone & Webster Engineering Corporation*

Boiler and Auxiliaries

BOILER
Combustion Engineering Company, Inc.—One bent-tube type, three fusion-welded drums; 10,000 sq ft boiler heating surface; water walls 4000 sq ft additional.

STEAM DRUMS
Diameter of drums, front 48 in., rear 54 in., bottom 36 in. Boiler constructed for 950 lb per sq in.; capacity 320,000 lb per hr actual evaporation.

SUPERHEATER
The Superheater Company—One Elesco convection type 2 in. O.D. tubing, 915 sq ft effective heating surface, designed for 915 F total temperature at 320,000 lb per hr. Temperature automatically controlled by operating dampers to bypass a portion of boiler gases.

ECONOMIZER
One Elesco fin-tube economizer with 6950 sq ft effective heating surface, designed to raise feedwater temperature 80 deg F with flow of 320,000 lb per hr.

SOOT BLOWERS
Diamond Power Specialty Company—8 units for boiler and superheater.

AIR PREHEATERS
The Air Preheater Corporation—Two Ljungstrom regenerative horizontal-shaft type each with 13,000 sq ft effective heating surface, designed to raise air temperature 435 deg F when boiler is operating at full output and burning natural gas.

FUEL BURNERS
Peabody Engineering Corporation—Six type H combined gas and oil, wide range, mechanical atomizing. Gas pressure 10 lb per sq in., oil pressure 250 lb.

FORCED-DRAFT FAN
B. F. Sturtevant Company, Inc.—One double inlet Turbovane type, direct-connected to wound-rotor induction motor. Capacity of fan ample to handle 378,000 lb of air per hour and maintain pressure of 8.85 in. of water at air preheater inlets when boiler is operating at full output and burning natural gas.

INDUCED-DRAFT FAN
American Blower Corporation—One double-inlet Sirocco type, direct-connected to wound-rotor induction motor. Capacity of fan ample to handle 446,000 lb of flue gas per hour and maintain draft of 9.6 in. of water at air preheater outlets when boiler is operating at full output and burning natural gas.

COMBUSTION CONTROL
Bailey Meter Company—Pneumatic operation, impulses taken from steam pressure to control rate of fuel supply, speeds of forced-draft and induced-draft fans and other adjustments. Control of feedwater to the boiler is independent.

STEEL PLATE WORK
Orange Car and Steel Company—Steel-plate smoke flue and forced- and induced-draft air ducts.

CHIMNEY
The Rust Engineering Company—One of reinforced concrete construction entirely brick lined; 16 ft inside diameter at top and 120 ft high above mat.

Feedwater System

BOILER FEED PUMPS
Worthington Pump and Machinery Corporation—Three 6-in., six-stage volute centrifugal, horizontal, single-suction type, two direct-connected to constant-speed motors and one direct-connected to a Terry steam turbine. Total dynamic head 2400 ft when boiler is operating at full output, speed 3550 rpm for normal conditions.

FEEDWATER REGULATORS AND EXCESS PRESSURE CONTROL VALVES
The Swartwout Company—Four constant differential pressure, thermal-hydraulic generator type.

EXTRACTION HEATERS
Foster Wheeler Corporation—One first-point bleed, direct contact heater and one third-point bleed, direct-contact heater.
The Griscom-Russell Company—One second-point bleed closed heater.

EVAPORATOR
The Griscom-Russell Company—One single-effect evaporator ordinarily to produce vapor at about 65 lb per sq in. gage using steam at about 155 lb. Coil surface 300 sq ft, tubes 1 in. O.D.

Turbine-Generator and Auxiliaries

TURBINE-GENERATOR
Westinghouse Electric & Manufacturing Company—One 25,000-kw, 3600-rpm tandem-compound, double-flow condensing unit having an overload capacity sufficient to develop 31,250 kw from the main generator and 2500 kw from the auxiliary generator on the extension to the main shaft, and 26 kw from the exciter of the auxiliary generator also on the shaft extension. Three openings for extraction of steam. A turning gear is included. Steam pressure 850 lb sq in. gage, 900 F total temperature. Main generator, 3 phase, 60 cycles, 13,800 volts, 0.8 power factor, wound for excitation at 250 volts.

EXCITER
Westinghouse Electric & Manufacturing Company—One 120-kw, 250-volt, 1200-rpm motor-generator set for the main generator.

Surface Condenser System

SURFACE CONDENSER
Westinghouse Electric & Manufacturing Company—One 29,700 sq ft of cooling surface, welded shell construction, but with cast-iron water boxes. Two-pass type, 21 ft active tube length and with two circulating water pumps having a combined capacity of 32,000 gpm.

CONDENSER TUBES
Bridgeport Brass Company—7/8 in. O.D., 18 Bwg. Admiralty mixture.

WATER VALVES
Chapman Valve Manufacturing Company—Hydraulic and motor operated.

INTAKE WATER SCREENS
Link-Belt Company—Two vertical traveling type.

SLUICE GATES AT INTAKE WELL
Chapman Valve Manufacturing Company—Four 84-in. × 84-in.

DE-SLIMING PROCESS
Wallace & Tiernan Products, Inc.—Chlorinators and accessories to inject chlorine gas into condenser-circulating water tunnels.

Switchgear

GENERATOR OIL CIRCUIT BREAKERS
Westinghouse Electric & Manufacturing Company—Type 033-A indoor solenoid-operated cell type.
STATION SERVICE
Westinghouse Electric & Manufacturing Company—for the large 2200-volt motor-driven auxiliaries.

Instruments

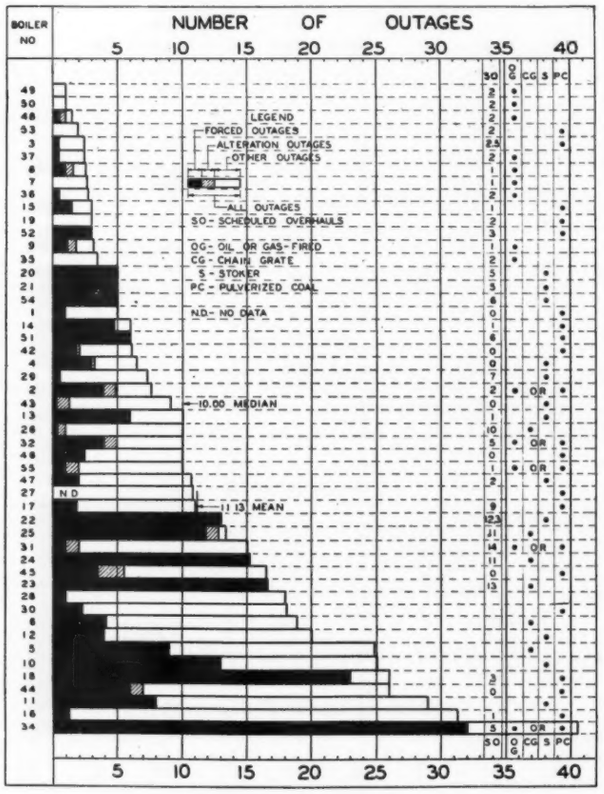
BOILER METER —*Bailey Meter Company*
DRAFT GAGES AT BOILER —*Ellison Draft Gage Company*
STEAM-FLOW METERS —*Bailey Meter Company*
RECORD. THERMOMETERS—*Leeds & Northrup Company*
IND. PRESSURE GAGES—*Consolidated Ashcroft Hancock Co., Inc.*
IND. THERMOMETERS —*Taylor Instrument Companies*
LEVEL AND VACUUM INSTRUMENTS —*Bailey Meter Company*
BAROMETER —*Taylor Instrument Companies*
CO_2 CONDUCTIVITY AND pH RECORDERS —*Leeds & Northrup Company*

Miscellaneous Equipment

PIPING —*Midwest Piping & Supply Company*
PIPE COVERING —*Johns-Manville Sales Corporation*
VALVES
Boiler safety —*Crosby Steam Gage & Valve Company*
Boiler stop check —*The Edward Valve & Mfg. Company*
Boiler feed check valves —*The Lunkenheimer Company*
Boiler blowoff —*Yarnall-Waring Company*
High-pressure steam gate —*Chapman Valve Mfg. Company*
Controls at extraction heaters —*The Swartwout Company*
Shut-off valves at extraction heaters —*Ruggles-Klingemann Mfg. Company*
Reducing pressure valves and float controls —*Mason-Neilan Regulating Company*
Atmospheric relief valve —*Atwood & Morrill Company*
HEATER DRIP PUMPS —*The Turbine Equipment Co. of New England*
CONTINUOUS BLOWDOWN HEAT EXCHANGER —*Griscom-Russell Company*
VACUUM PRIMING PUMPS AND TANKS —*Nash Engineering Company*
DISTILLED WATER PUMPS —*Ingersoll-Rand Company*
CONDENSATE BOOSTER PUMPS —*Foster-Wheeler Corporation*
WATER SUMP PUMPS —*Ingersoll-Rand Company*
LUBRICATING OIL PURIFICATION EQUIPMENT —*S. F. Bowser & Co., Inc.*
FUEL OIL STORAGE TANK —*Petroleum Iron Works Co., Inc.*
FUEL OIL PUMP —*Quimby Pumps Agency*
FUEL OIL HEATER —*Griscom-Russell Company*
NATURAL GAS METER —*American Meter Company*
GAS PIPING STRAINER—*Elliott Company*

A Study of Boiler Outages

The recently issued report of the Prime Movers Committee, E. E. I., on "Boilers, Superheaters, Economizers, Air Heaters and Piping" contains the results of a study on boiler outages during 1936, covering 30 plants, 57 types of boiler and furnace arrangements and 182 individual boilers. Data are included to show the nature, frequency and duration of outages, as well as the frequency, amount and cause of all work done on boiler components and accessories. Outages are classified as "forced," "scheduled" and "alterations," and detailed information is given under these headings for each boiler. While the boilers are identified by number only and the name of the plant is not given, sufficient data are given for each installation, including that on fuel and feedwater, to afford a comprehensive understanding of the operating conditions.



Number of outages with boilers arranged in order of ascending frequency

The ages of boilers for which data were submitted ranged from 1 to 23 years and the operating service from 8100 to 122,000 hours. However, there was no observable relation between age or service hours and the number or character of the outages.

The chart shows the total number of outages arranged in the order of ascending frequency. These are broken down into forced, scheduled and alteration outages and the type of firing is indicated in each case.

While the boilers fired with oil, gas or pulverized coal predominate in the lower outage range, the occurrence of all four types of firing (including stokers) in the complete outage range indicates that the type of firing is not necessarily a determining factor with respect to the number of outages. Also, there were no indications that steaming rates, relative to design capacity, pressure, temperature or furnace heat release, were specific determinants with respect to either the number of outages or the outage time.

The following table, which is one of many included in the report, gives a summary of the forced outage frequency and duration data.

SUMMARY OF FORCED OUTAGE FREQUENCY AND DURATION DATA

Component	Number of Boilers Having Component	Per Cent of Boilers Having Forced Outage Jobs on Component	Frequency Median	Frequency Mean	Duration Median	Duration Mean
Stokers	18	72.2	0.80	1.95	44	114
Radiant superheaters	14	71.5	2.22	3.0	30	52
Economizers	38	50.0	0.67	2.76	22	53
Boiler tubes	57	42.1	0.50	0.87	28	41
Convection superheaters	54	40.7	0.75	1.83	32	96
Furnace refractories	38	34.2	1.0	3.83	51	67
Wall tubes	50	26.0	1.0	1.18	36	88
Induced draft fans	46	21.7	0.65	0.62	60	71
Precipitators	10	20.0	1.0	1.0	89	89
Boiler tube headers	45	15.6	1.0	1.48	24	85
Water fittings	57	14.0	0.29	0.42	7	7
Forced draft fans	43	11.6	0.33	0.53	24	24
Steam fittings	57	10.5	0.35	0.36	5	16
Air heaters	35	8.6	0.5	0.83	12	12
Combustion equipment	39	7.7	0.5	0.78	14	20
Wall tube headers	50	6.0	0.5	0.67	8	9
Boiler drums	57	5.3	0.25	0.79	6	7
Safety valves	57	5.3	0.5	0.44	2	4
Baffles, dampers	57	3.5	0.23	0.23	29	29
Wall tube circulators	50	2.0	0.5	0.50	6	6
Soot blowers	57	1.8	0.25	0.25	1	1
Ash hoppers	57	1.8	0.34	0.34	49	49

From the mass of data submitted the report concludes that the mean number of outages, from all causes, per boiler-year was 11.3 for 52 boilers that were averaged, and the median was 10; that is, there were as many boilers that had more than 10 outages per year as there were boilers that had fewer outages. The mean number of forced outages per boiler-year was 4.67 for 56 boilers and the median was 2.75. The mean percentage of total outage time was 12.34 and the median 9.9, whereas the mean percentage of forced outage time was 2.06 and the median 1.14.

High-Pressure Test Boiler

To meet the demand for boiler equipment designed to withstand increasingly high temperatures and pressures, the Clees Valve and Engineering Company is installing a new boiler in its testing laboratory at Newark, N. J., to provide steam at a pressure of 2500 lb per sq in. It probably will go into service this month and will be used in testing recently developed types of forged-steel valves, some of which are made to withstand pressures up to 2500 lb per sq in. Valves of this type are now being produced in sizes up to 8 in., whereas $2^1/_2$ in. was the previous maximum size for such valves.

This boiler supplements existing testing equipment capable of supplying steam at 1500 lb per sq in. and hydraulic facilities for tests up to 10,000 lb per sq in. pressure.

Testing Steam Condensate For Its Quality and Purity

By P. B. PLACE

Combustion Engineering Company, Inc.

A discussion of the measurement of impurities in steam with particular reference to the distillation method of testing condensed samples. The accuracy of this method depends largely upon the elimination of dissolved gases in the steam and means of accomplishing this are described. Results determined by present methods vary in accuracy inversely with the purity of the steam and the author's conclusion is that it is very difficult to check the absolute purity of steam containing less than 1 ppm.

IN the past few years increasing emphasis has been put on the desirability of clean steam. Carryover of small amounts of boiler water, containing relatively high concentrations of dissolved salts, results in deposits in superheaters and turbines that may interfere seriously with the efficient performance of this equipment. Where formerly it was acceptable to deliver from the boiler, steam containing less than one half of one per cent of boiler water, it is now becoming the practise to specify a limit to the amount of dissolved salts in a sample of the condensed steam.

The moisture in saturated steam, as determined by calorimetric methods, is generally reported in per cent by weight of the mixture, and dry steam in per cent by weight of the mixture is known as the quality of the steam. The amount of solids contained in the moisture, which may be deposited when that moisture is evaporated in the superheater, is too small to be conveniently expressed in terms of per cent and is generally reported as parts per million parts of steam. Since the definition for quality is well established, it has been suggested that the term impurity be used when referring to the solids content of steam. Thus quality and impurity become two distinct characteristics of steam, and two steams of the same quality may have considerably different amounts of impurity.

The calorimetric determination of moisture can be made only on saturated steam and the accuracy of the determination is inversely proportional to the amount of moisture present. The errors involved in calorimeter work are more or less constant so that a much greater accuracy can be expected in the determination of one per cent moisture than in the determination of one-tenth of one per cent moisture. The following shows the probable degree of accuracy in the moisture determinations under average conditions.

APPROXIMATE PERCENTAGE ERROR IN MOISTURE DETERMINATIONS

Per cent moisture in steam	Possible per cent error in the moisture determination
2.0	2.5
1.0	5.0
0.5	10.0
0.1	50.0

From a quality standpoint, these relatively large errors are not serious because one- or two-tenths per cent moisture has little effect on superheat and represents only a small error in the percentage of dry steam.

The moisture determination is to the steam quality what the heat balance is to the boiler efficiency. From an impurity standpoint, however, this type of error is a serious complication and this limitation should be considered in the direct determination of small amounts of solid carryover by any method.

With boilers operating without steam washers and when the solid and moisture carryover is relatively high, mutual checks on quality and impurity may be obtained by determining the quality and calculating the impurity on the assumption that the concentration of salts in the moisture in the steam is the same as the concentration of salts in the boiler water, or by determining the impurity and similarly calculating the quality. Thus, saturated steam generated from boiler water containing 1000 ppm of dissolved salts and testing 0.2 per cent moisture should contain 2 ppm of solid carryover. As the carryover decreases it becomes more difficult to balance the determinations.

For boilers operating with steam washers, moisture or solid carryover cannot be calculated from impurity or quality determinations because of the uncertainty of the proportions of boiler and feedwater in the moisture in the steam. Often such calculations will give absurd comparisons that indicate large errors in the determinations. For example, a boiler operating with boiler water concentrations of 600 ppm is equipped with a steam washer using a condensate feedwater having a concentration of 5 ppm. Quality determinations by calorimeter show 0.2 per cent moisture in the steam and conductivity measurements show 2 ppm. Balancing these values on the assumption that the washing efficiency in the steam washer is 25, 50, 75 or 100 per cent we get:

Per cent washing efficiency—assumed	25	50	75	100
Solids in boiler water, ppm	600	600	600	600
Solids in feedwater, ppm	5	5	5	5
Calculated solids in moisture in steam, ppm	451	303	154	5
Solids in 0.2 per cent moisture steam, ppm	0.90	0.61	0.30	0.06
Solids in steam by determination, ppm	2.0	2.0	2.0	2.0

Operation and practical tests of steam washers have proved their effectiveness and it may safely be assumed that the washing efficiency (substitution of feedwater for boiler water in the moisture in the steam) is 75 per cent or higher. Whereas, in the above case, estimation of expected performance would justify a guarantee of less than one-half of one part per million in the steam, it would be very difficult to prove such purity, average results being more as indicated in the foregoing table.

Impurity of steam may be determined on condensed samples of either saturated or superheated steam. The methods developed by several investigators and the apparatus involved have been described and will not be repeated here. It may be pointed out, however, that the same difficulty exists in this determination as in the moisture determination. As the impurity becomes smaller it is increasingly difficult to determine the amount accurately. It is probable that with the present methods of testing, determinations of impurity of less than one-half part per million may be 50 to 100 per cent in error. Furthermore, these determinations are invariably too high because the errors involved are such that it is almost impossible to get low results.

In developing test methods, continuous sampling and measurement has been and should be a primary aim. Occasional samples or tests that require considerable time are not suitable for practical control in a power plant. Such tests may, however, be more accurate and are of value as checks on a routine method.

Direct gravimetric determination of the solids in steam condensate is an alternative method, which requires considerable time and very careful manipulation. This method can give accurate results down to two parts per million but the difficulties involved and the probable error increase rapidly below this concentration. The most convenient and most accurate method of determining impurity involves the determination of the electrical conductivity of samples of condensed steam. Conductivity can be measured accurately, quickly and continuously.

The error in the conductivity method lies not so much in the measurement itself as in the conversion of the conductivity values to equivalent solids concentration and in the elimination of or correction for dissolved gases in the steam samples. If the conductivity of the sample is wholly due to dissolved salts, and if the relative proportions of the various salts are known, a conversion factor can be calculated from the specific conductance of the various salts that will give reasonably accurate results. The value of this conversion factor may be between 0.4 and 0.6 and, in the absence of definite information, it is often necessary to assume an average value of 0.5 for this factor. If further, there are present in the steam, acid or basic gases which, when dissolved in the condensed sample, give conductivity values but which do not, on evaporation, yield a solid, then either these gases must be eliminated or some correction made for their presence. For instance CO_2 and NH_3 are often present in steam in quantities sufficient to account for a large percentage of the conductivity of the condensate.

The logical method of dealing with condensates containing conductive gases is to eliminate the gases. A number of methods have been devised for this purpose. Boiling and wasting a portion of the sample as steam has been the basis of one method; another involves subjecting the sample to a very high vacuum; and a third is to displace the conductive gases by scrubbing the sample with an excess of a non-conductive gas. While all of these methods have been partially successful in eliminating the bulk of the conductive gases they have not completely solved the problem and they require elaborate apparatus and constant control. It is felt that despite the care exercised, conductivity tests indicate higher salt concentrations in the steam than are actually present when these concentrations are less than one part per million.

In an attempt to eliminate the effects of dissolved gases a method involving the distillation of condensed steam samples was developed and will be described in detail. Although this method has definite limitations, the results obtained have been consistently lower than given by other methods and have indicated that the latter may show a higher salt concentration than is actually present.

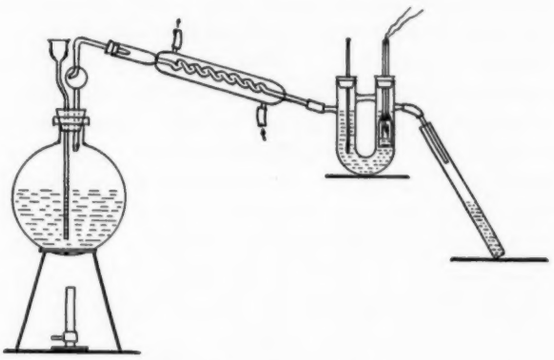


Fig. 1—Apparatus for distillation of steam condensates

The apparatus involved is shown in Fig. 1. The test procedure is to distill about two liters of condensate in a three-liter Pyrex flask. The steam after passing through a Pyrex distilling trap and a Pyrex coil condenser, flows through a flow-type conductivity cell and thence into a 100-cc Nessler tube. The rate of distillation is about 10 cc per min and the conductivity of the distillate is measured periodically. Each 100 cc caught in the Nessler tube is titrated for CO_2 using N/44 NaOH, and phenolpthalein as an indicator. This CO_2 determination is not involved in the calculated results but is indicative of the progress of the test.

If the sample contains appreciable amounts of volatile impurities, they will come over with the first few hundred cc of distillate, redissolve as the latter is condensed, and register as a hump in the plotted conductance curve of the distillate. If the volatile impurity is CO_2, the titrations of the first few samples in the Nessler tube will show high results, often several times the amount of CO_2 as shown by titration of the original sample. As the distillation continues, and the CO_2 is eliminated, the conductance of the distillate falls to a minimum and the titrations indicate less than 1 ppm of CO_2. When the conductivity of the distillate has leveled off at a minimum value, the distillation is stopped. The residue in the flask is cooled down, and its volume and conductivity measured. From the data obtained, the conductivity and solids content of the original sample is calculated to a gas free basis.

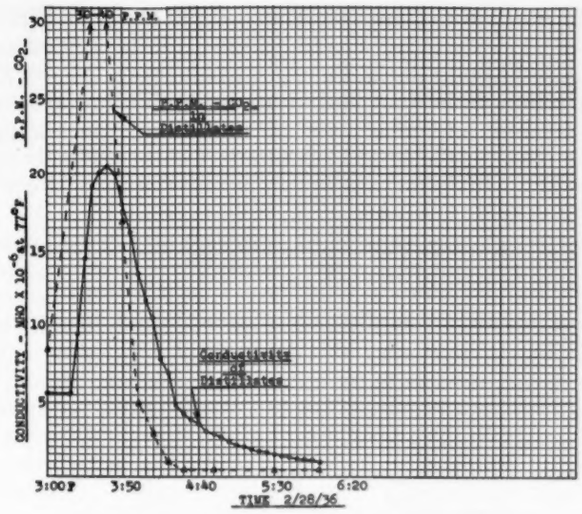


Fig. 2—Typical results of distillation test

Fig. 2 shows typical results of a distillation test on a condensed steam sample. The original sample of 2300 cc had a conductance of 5.6×10^{-6} mho and titrated $8^1/_2$ ppm of CO_2. Boiling started at 3:15 p.m. and the concentration of the CO_2 in the first few hundred cc of distillate is evident from both the titration results and the conductance values. With elimination of the CO_2, the conductance fell off to a minimum of 1 mho. The distillation was stopped at this point because the conductivity meter was not designed to read conductivity of less than 1×10^{-6} mho. The conductivity of the 300 cc concentrated residue in the flask was 2.9×10^{-6} mho, which is much lower than the conductance of the original sample, in spite of probable contamination during the distillation process.

Assuming that all of the solids in the original sample are in the concentrated 300 cc residue, that all of the volatile impurities have been distilled off, and that no contamination of the sample has occurred during the distillation, we may calculate the gas free conductance of the original sample as follows:

$$\frac{(2.9 \times 10^{-6}) \times 300 \text{ cc}}{2300 \text{ cc}} = 0.38 \times 10^{-6} \text{ mho}$$

For a conversion factor of 0.55 ppm per mho, the actual salt concentration in the steam is $0.38 \times 0.55 = 0.2$ ppm, as compared with $5.6 \times 0.55 = 3.1$ ppm, as calculated from the original sample conductance. Thus, in this case the CO_2 and other volatile impurities in the sample accounted for over 90 per cent of the conductance of the sample.

A modification of this method is shown in Fig. 3. A sample of 2290 cc, having a conductance of 5.7 and titrating 12 ppm of CO_2, was distilled as outlined above until most of the CO_2 had been eliminated. At 1:50 p.m. a fresh sample was added to the distilling flask in 10 cc amounts at the same rate as distillation. The sample was added through the thistle tube shown in Fig. 1. Thus, an attempt was made to maintain a gas evolution equal to that in the sample and to attain an equilibrium between volatile impurities evolved and the conductance of the distillate. As seen in Fig. 3 both the CO_2 in, and the conductivity of the distillate increased and leveled off at the values shown. After holding equilibrium conditions for an hour, the addition of fresh sample was stopped and distillation finished as outlined above. In this manner two sets of data were acquired from which independent calculations could be made of purity.

The calculations for the equilibrium conditions involve the assumption that the 4.8 mho conductance of the distillate at equlibrium conditions is due wholly to the volatile impurities in the sample. The conductance of the sample due to actual salts is, therefore, $5.7 - 4.8 = 0.9$ mho, and its equivalent salt concentration is $0.9 \times 0.55 = 0.5$ ppm.

Note that in this calculation the conductance of the residue is not involved. Checking this calculation by the method given for the first example, involving the conductance of residue and final distillate, we get:

$$2290 + 700 = 2990 \text{ cc sample used}$$
$$2990 - 290 = 2700 \text{ cc distilled}$$
$$\frac{8.2 \times 290}{2990} = 0.8 \text{ mho}$$
$$0.8 \text{ mho} \times 0.55 = 0.4 \text{ ppm.}$$

as compared with 0.5 ppm as calculated from the equilibrium data.

An objection might be raised that carryover during the distillation deconcentrates the residue and results in erroneous calculations. In the case given in Fig. 2, it may be assumed that the conductivity of the distillate has leveled off at a minimum of 1 mho. If it is suspected that this minimum is the result of carryover rather than the last traces of volatile impurities, the following calculations may be used to correct for this condition. A constant carryover of 1 mho for the duration of the distillation would require a correction to the residue of:

$$2000 \text{ cc} \times 1.0 \text{ mho} = 2000$$
$$300 \text{ cc} \times 2.9 \text{ mho} = 870$$
$$\text{Corrected residue} = \frac{2870}{300} = 9.6 \text{ mho}$$

Calculating this concentrated residue back to original dilution gives

$$\frac{9.6 \times 300}{2300} = 1.3 \text{ mho due to salts}$$

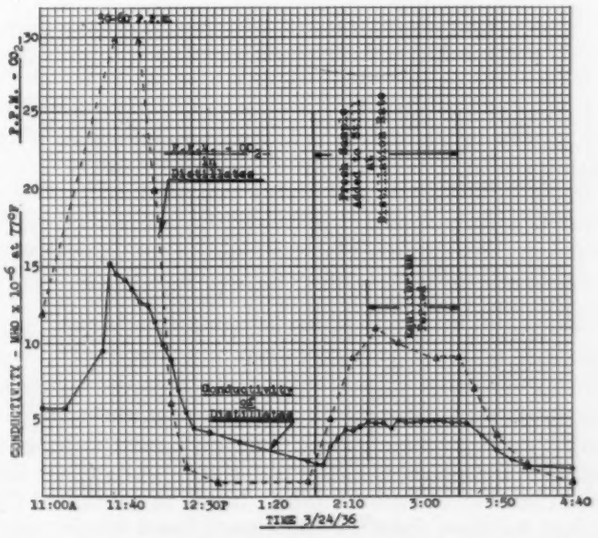


Fig. 3—Modification of method used in Fig. 2

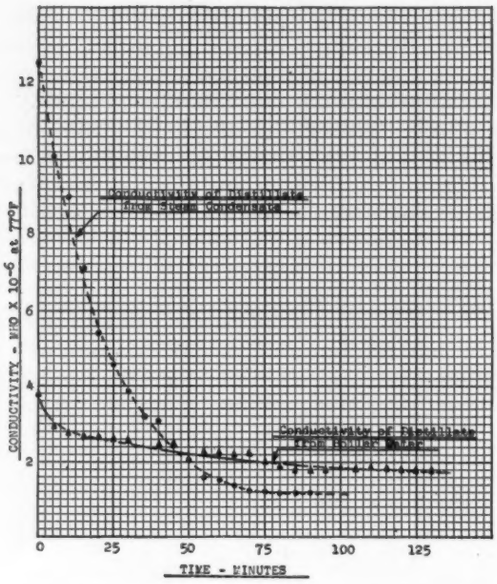


Fig. 4—Conductivity of boiler water and condensate

and calculating the equivalent concentration of salts gives:

$$1.25 \times 0.55 = 0.7 \text{ ppm.}$$

Thus, with this method we may calculate limits of purity, in this case a maximum of 0.7 and minimum of 0.2 ppm.

Similar corrections applied to the test shown in Fig. 3 give the following results:

1. $5.7 - (4.8 - 1.8) = 2.7$ mho
   $2.7 \times 0.55 = 1.5$ ppm.
2. $(290 \times 8.2) + (2700 \times 1.8) = 7238$
   $7238 \div 290 = 24.9$
   $\dfrac{24.9 \times 290}{2990} = 2.4$ mho
   $2.4 \times 0.55 = 1.3$ ppm.

These values are obviously maximums and the correct value is probably closer to the first calculations. The two samples used for the tests shown in Figs. 2 and 3 are not duplicate samples, that in Fig. 3 being taken at a higher rate of steaming.

Conductivity balances made on test results have shown that the conductivity of the combined distillate and residue is generally higher than the conductivity of the original sample despite a loss of CO_2 during the tests. It may be expected that boiling the sample in glass apparatus over a period of two to three hours will contaminate the sample and conductivity balances indicate that this contamination may be 10 to 20 per cent. It is evident from the calculations that this contamination is included in the calculated purity, so that the calculated results tend to be high.

That there is little if any deconcentration of the sample by carryover during the distillation is indicated by the results shown in Fig. 4. Two samples were similarly distilled, one a sample of condensed steam having a solids concentration not over 2 ppm and the other a sample of the corresponding boiler water having a solids concentration of over 400 ppm. It will be noted that the initial distillate from the condensate has a considerably higher conductivity than that from the boiler water and that the final distillates level off at about the same point. A similar check was made by evaporating a 1000 cc sample of boiler water having a conductivity of 815 × 10^{-6} mho, to 580 cc. The cooled residue left in the flask had a conductivity of 1400 × 10^{-6} mho. Calculating this back to the original dilution gives a conductivity of 812 × 10^{-6} mho which checks with the original conductivity of the sample.

Although this method has obvious limitations, it is offered as an alternate check method. On steam known to contain large amounts of CO_2 it has given consistently lower concentration than other methods and since it is difficult to make errors on the high side with any method, it has served to set a lower limit on test results.

The complete elimination of volatile impurities from steam condensates requires both time to establish equilibrium between the gas in and above the liquid and a flow to continuously upset that equilibrium. To eliminate gases from water by boiling in a closed system, requires the distillation of part of the liquid, the flow of vapor serving as a carrier for sweeping out the gases liberated by the boiling process. Tests on samples boiled in open beakers indicate that a few minutes boiling will eliminate all but 2 to 3 ppm of CO_2 and the effect of heating separate samples to different temperatures is shown by the following tests on a sample that titrated 17 ppm of CO_2 as sampled.

Temperature—°F	Ppm CO_2 (by titration)
78 (original)	17
98	16
118	13
138	11
158	7
178	4
Boiled vigorously	2

Fig. 5 shows the rate of CO_2 elimination and corresponding changes in the conductivity of the distillate of a number of samples tested by the above distillation method. These tests indicate that elimination of gases by boiling in a closed system requires distillation of 10 to 20 per cent of the sample to furnish flow for removing the liberated gas.

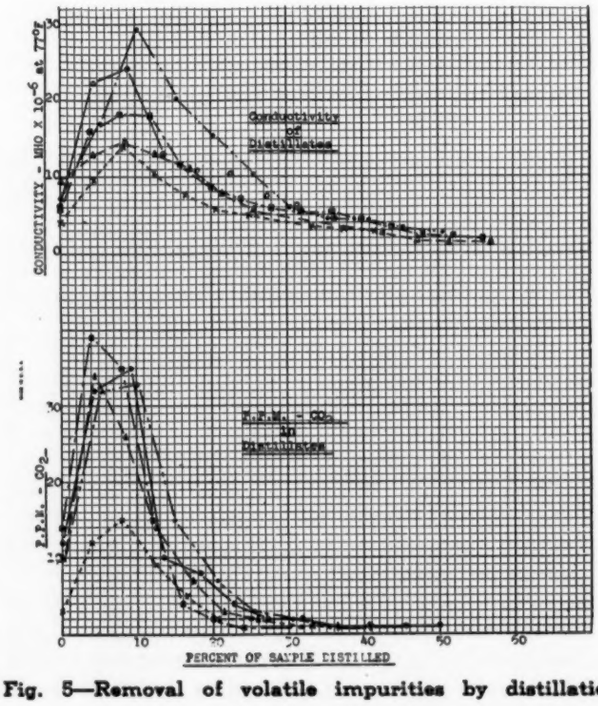


Fig. 5—Removal of volatile impurities by distillation

The Economics of SUBSIDIZED POWER

By FRANK F. FOWLE†
Consulting Engineer, Chicago

This paper was presented at the 22nd Annual Fuel Engineering Conference sponsored by Appalachian Coals, Inc., at Atlanta, Ga., February 8, 1938. It represents a continuation of the author's paper entitled, "The Nation's Power Supply"[1] which was delivered before the Midwest Power Conference in Chicago in April 1936. The present paper analyzes the costs of generating steam and hydro power for various initial investments per kilowatt under normal conditions and under subsidized conditions. A similar analysis is applied to transmission costs.

DURING the past two years there has been extensive discussion of electric power costs both in the technical press and in many newspapers and magazines of general circulation. The trend of independent engineering opinion is well known, but recently there have been some interesting assertions from advocates of public enterprise in the utility field that hydro power is cheaper than steam power. Where figures have been advanced to support this assertion, an examination of them discloses that the comparison is drawn between steam power generated by private enterprise and hydro power generated by public enterprise. Furthermore, it is assumed in those comparisons that private enterprise must bear the normal cost of capital and the full burden of taxes, whereas public enterprise is subsidized by obtaining capital at about half the normal cost to private enterprise and by complete relief from taxation.

Almost the first question which presents itself is why such a comparison should be set up on a one-sided or prejudiced basis. If a subsidy is assumed on one side of the comparison, why should it not be assumed on both sides? The next question, obviously, is what effects these subsidies will have on the cost of power, if granted impartially to both types of generation set up in the comparison. In this paper the same subsidies are applied to both types of generation, to show how they affect the cost of power in both instances, and, of course, how they affect the comparison.

Basis of Subsidy

Annual charges on the plant investment, comprised of return on capital, taxes, depreciation and an allowance for overhead, have been taken at 12.5 per cent on the steam plant and 10.5 per cent on the hydro plant. These totals include normal return on capital at 7 per cent and taxes at 2 per cent, in both cases. The subsidy is assumed to consist of a reduction of 3.5 per cent in the return on capital and the omission of the 2 per cent allowance for taxes, or a combined reduction of 5.5 per cent from the previous totals. The breakdown in detail is shown below.

SCHEDULE OF ANNUAL CHARGES, PER CENT

	At Full Normal Cost		Under Subsidy	
	Steam	Hydro	Steam	Hydro
Interest	7.0	7.0	3.5	3.5
Taxes	2.0	2.0	—	—
Depreciation	3.0	1.0	3.0	1.0
Overhead	0.5	0.5	0.5	0.5
Totals	12.5	10.5	7.0	5.0

The annual charges on the transmission line, including the step-up and step-down terminals, have been taken at 12.5 per cent for the full normal cost and 7.0 per cent for the subsidized cost. However, in these two cases the item of 3 per cent for depreciation is assumed to cover both depreciation and repairs, whereas in the case of generating plants the cost of repairs is taken care of under another item.

Comparative Cost of Generation

Comparison of generation costs has been set up on the assumption that the steam plant is 100 per cent dependable, up to its full installed capacity, and that the firm capacity of the hydro plant is 100 per cent dependable. Both of these figures would be shaded in operating practice, but for purposes of comparison any prejudice is eliminated by taking both as 100 per cent dependable. The general question of available reserve capacity is left out of the picture on both sides, to simplify the comparison. It is also assumed in all instances that the generating plant includes no step-up substation for transmission or distribution; that is to say, power is delivered only to the station bus, at generator voltage.

The estimated costs of generation, for steam and hydro, under normal rates for capital and taxes, are shown in Table 1, the hydro plant having been extended to cover a range of cost per kilowatt of firm capacity from $250 down to $100, in $50 steps.

Table 2 shows the corresponding data, set up in the same way, under subsidized costs as previously explained. The cost of generation per kilowatt-hour shown in these two tables is summarized as follows:

SUMMARY OF GENERATION COSTS, MILS PER KILOWATT-HOUR

		Hydro			
	Steam	At $250 Per Kw	At $200 Per Kw	At $150 Per Kw	At $100 Per Kw
Normal Basis	3.97	6.30	5.10	3.90	2.70
Subsidized Basis	2.90	3.15	2.58	2.01	1.44

† Past-President, Western Society of Engineers.
[1] Published in full in the *Journal* of the Western Society of Engineers, June 1936; in abstract in *Electrical World* of May 23, 1936; and quoted by Dr. A. A. Potter in his contribution on "The Production of Power" as published by the National Resources Committee in June 1937.

TABLE 1

COMPARISON OF GENERATION COSTS UNDER NORMAL RATES FOR CAPITAL AND TAXES:

STEAM PLANT AT MINE MOUTH VERSUS HYDRO PLANT AT DAM SITE

(1)	Steam Plant Located at Mine Mouth (2)	Hydro Plant Located at Dam Site			
		Cost $250 per Kw. (3)	Cost $200 per Kw. (4)	Cost $150 per Kw. (5)	Cost $100 per Kw. (6)
Total Installed Capacity (Kw)	100,000	100,000	100,000	100,000	100,000
Cost per Kw. of Installed Capacity	$85	$250	$200	$150	$100
Total Cost of Plant	$8,500,000	$25,000,000	$20,000,000	$15,000,000	$10,000,000
Annual Load Factor (Per Cent)	50	50	50	50	50
Annual Output, Kilowatt-Hours	438,000,000	438,000,000	438,000,000	438,000,000	438,000,000
Annual Fixed Charges (Per Cent)	12.5	10.5	10.5	10.5	10.5
Annual Fixed Charges (Dollars)	$1,063,000	$2,625,000	$2,100,000	$1,575,000	$1,050,000
Pounds of Coal per Kilowatt-Hour*	1.18	-	-	-	-
Annual Coal Consumption (Tons)	259,000	-	-	-	-
Annual Cost of Coal at $1.60 per Ton	$414,000	-	-	-	-
Operating Supervision, Labor and Repairs**	$263,000	$131,000	$131,000	$131,000	$131,000
Total Annual Cost (Dollars)	$1,740,000	$2,756,000	$2,231,000	$1,706,000	$1,181,000
Cost per Kilowatt-Hour (Mils)	3.97	6.30	5.10	3.90	2.70
Recapitulation:					
(a) Fixed Production Costs: Mils per Kw-Hr.	2.43	6.00	4.80	3.60	2.40
(b) Variable Production Costs: Mils per Kw-Hr.	1.54	0.30	0.30	0.30	0.30
(c) Total Production Costs: Mils per Kw-Hr.	3.97	6.30	5.10	3.90	2.70

*Based on plant efficiency of 13,000 B.t.u. per kilowatt-hour and heating value of 11,000 B.t.u. per pound of coal.

**Estimated at 0.6 mil per kilowatt-hour for steam plant and 0.3 mil for hydro plant.

TABLE 2

COMPARISON OF GENERATION COSTS UNDER SUBSIDIZED RATES FOR CAPITAL AND TAXES:

STEAM PLANT AT MINE MOUTH VERSUS HYDRO PLANT AT DAM SITE

(1)	Steam Plant Located at Mine Mouth (2)	Hydro Plant Located at Dam Site			
		Cost $250 per Kw. (3)	Cost $200 per Kw. (4)	Cost $150 per Kw. (5)	Cost $100 per Kw. (6)
Total Installed Capacity (Kw)	100,000	100,000	100,000	100,000	100,000
Cost per Kw. of Installed Capacity	$85	$250	$200	$150	$100
Total Cost of Plant	$8,500,000	$25,000,000	$20,000,000	$15,000,000	$10,000,000
Annual Load Factor (Per Cent)	50	50	50	50	50
Annual Output, Kilowatt-hours	438,000,000	438,000,000	438,000,000	438,000,000	438,000,000
Annual Fixed Charges (Per Cent)	7	5	5	5	5
Annual Fixed Charges (Dollars)	$595,000	$1,250,000	$1,000,000	$750,000	$500,000
Pounds of Coal per Kilowatt-hour*	1.18	-	-	-	-
Annual Coal Consumption (Tons)	259,000	-	-	-	-
Annual Cost of Coal at $1.60 per Ton	$414,000	-	-	-	-
Operating Supervision, Labor and Repairs**	$263,000	$131,000	$131,000	$131,000	$131,000
Total Annual Cost (Dollars)	$1,272,000	$1,381,000	$1,131,000	$881,000	$631,000
Cost per Kilowatt-hour (Mils)	2.90	3.15	2.58	2.01	1.44
Recapitulation:					
(a) Fixed Production Costs: Mils per Kw-hr.	1.36	2.85	2.28	1.71	1.14
(b) Variable Production Costs: Mils per Kw-hr.	1.54	0.30	0.30	0.30	0.30
(c) Total Production Costs: Mils per Kw-hr.	2.90	3.15	2.58	2.01	1.44

*Based on plant efficiency of 13,000 B.t.u. per kilowatt-hour and heating value of 11,000 B.t.u. per pound of coal.

**Estimated at 0.6 mil per kilowatt-hour for steam plant and 0.3 mil for hydro plant.

These figures show that the subsidy favors hydro somewhat more than steam, because hydro costs are comprised in greater proportion of fixed charges. Under steam generation the subsidy reduces the cost of energy 27 per cent, whereas under hydro generation the subsidy reduces the cost by about 47 to 50 per cent in the cases shown. On a normal basis of cost, hydro generation is not cheaper than steam unless the hydro plant costs less than approximately $150 per kw. On a subsidized basis, hydro generation is cheaper when the hydro plant costs less than approximately $225 per kw. These comparisons include no transmission, in any instance.

In the matter of cross-comparisons, it is interesting to observe that subsidized steam generation is cheaper than hydro generation under normal costs unless the hydro plant costs less than approximately $110 per kw. On the other hand, subsidized hydro generation is cheaper than steam generation under normal costs unless the hydro plant costs more than approximately $320 per kw.

Comparative Cost of Generation and Transmission

Table 3, shows the estimated normal cost of energy transmission for three hypothetical cases: 200 miles at 220 kv, 100 miles at 132 kv and 50 miles at 66 kv when the hydro plant costs $250 per kw. Similar tables (not here reproduced) give the same data for hydro plants costing $200, $150 and $100 per kw. The results shown in these tables are summarized in Table 4, and the normal cost of hydro generation is added to the normal cost of transmission, producing the estimated total normal cost of energy delivered at the end of the line. These total costs are carried forward into Table 5, where the normal cost of steam generation (Table 1) is deducted, leaving the excess of hydro cost over steam, and the excess is converted into equivalent mileage of coal haul according to the following formula. The freight rate for average midwest conditions is taken as

$$\text{Rate per ton} = \$0.90 + \$0.0035\ L$$

where the item of $0.90 is a switching charge and L is the length of haul in miles. At the assumed efficiency of 1.18 lb of coal per kilowatt-hour, this formula can be expressed in mils per kwhr as follows:

$$\text{Freight cost per kwhr} = 0.531 + 0.002065\ L$$

The mileage of coal haul for equal total normal costs of energy is shown graphically in Fig. 1. Steam power is shown to be cheaper than hydro, for most localities, unless the cost of the hydro plant is less than about $125 per kw.

Table 6 shows the estimated subsidized cost of energy transmission under the same conditions of transmission as set forth in Table 3 and other tables (not here reproduced) give the transmission costs when the hydro plant costs $200, $150 and $100 per kw. The results are summarized in Table 7 and the subsidized cost of hydro generation is added to the subsidized cost of transmission, producing the estimated total subsidized cost of energy delivered at the end of the line. These total costs are carried forward into Table 8, where the subsidized cost of steam generation (Table 2) is deducted, leaving the excess of subsidized hydro cost over subsidized steam, and the excess is converted into equivalent

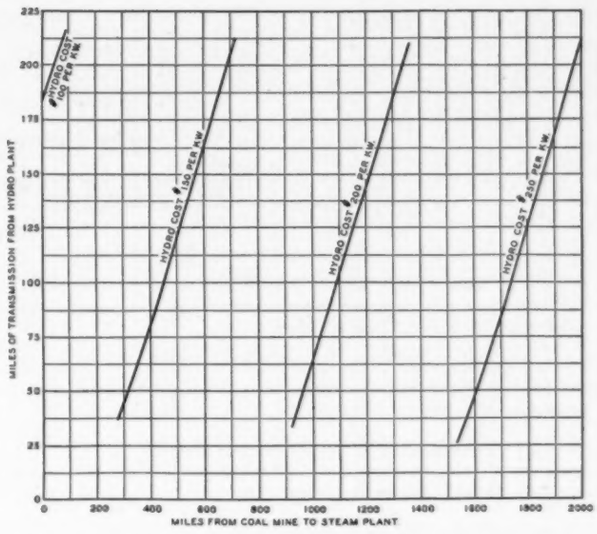

MILES OF TRANSMISSION FROM HYDRO PLANT
MILES FROM COAL MINE TO STEAM PLANT
HYDRO COST 100 PER KW.
HYDRO COST 150 PER KW.
HYDRO COST 200 PER KW.
HYDRO COST 250 PER KW.

Fig. 1—Equivalent mileage of coal haul (normal)

mileage of coal haul according to the formula previously stated. The mileage of coal haul for equal total subsidized costs of energy is shown graphically in Fig. 2.

Subsidized steam power is shown to be cheaper than subsidized hydro, for most localities, when the hydro plant costs $250 per kw. At a cost of $200 per kw for the hydro plant, and upward of 100 miles of transmission, steam power is still in the picture if the coal haul is rather moderate. At a cost of $150 per kw for the hydro plant, steam is out of the picture entirely. Comparison of Figs. 1 and 2 shows obviously that where subsidized steam power has the advantage in total cost over subsidized hydro power, the margin of that advantage

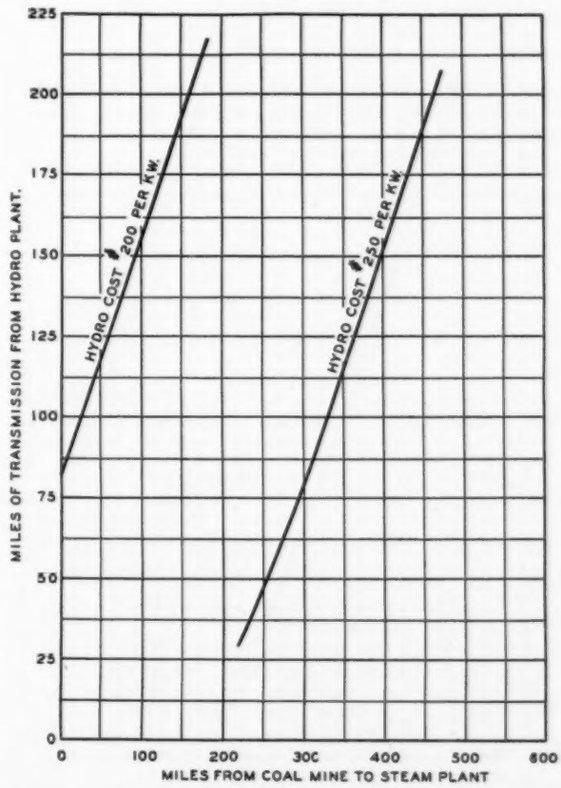


Fig. 2—Equivalent mileage of coal haul (subsidized)

TABLE 3

COST OF ELECTRIC TRANSMISSION FROM HYDRO PLANT

COSTING $250 PER KILOWATT: NORMAL RATES FOR CAPITAL AND TAXES

(1)	200 Miles At 220 Kv. Twin Circuits (2)	100 Miles At 132 Kv. Twin Circuits (3)	50 Miles At 66 Kv. Twin Circuits (4)
Rated Output Per Circuit (Kw)	150,000	60,000	25,000
Total Output, Two Circuits (Kw)	300,000	120,000	50,000
Annual Load Factor (Per Cent)	50	50	50
Annual Transmission Efficiency (Per Cent)	90	90	90
Annual Input, Kilowatt-hours	1,460,000,000	584,000,000	243,300,000
Annual Output, Kilowatt-hours	1,314,000,000	525,600,000	219,000,000
Transmission Loss, Kilowatt-hours	146,000,000	58,400,000	24,300,000
Cost of Complete Line, Per Mile	$50,000	$22,000	$13,000
Total Cost of Line	$10,000,000	$2,200,000	$650,000
Cost of Two Complete Terminals	$6,750,000	$2,400,000	$800,000
Total Cost of Transmission System	$16,750,000	$4,600,000	$1,450,000
Annual Fixed Charges (Per Cent)	12.5	12.5	12.5
Annual Fixed Charges (Dollars)	$2,094,000	$575,000	$181,000
Additional Capacity of Generating Plant Required to Compensate for Line Loss (Kw)	33,300	13,300	5,550
Cost of Additional Capacity, Per Kw.	$250	$250	$250
Total Cost of Additional Generating Plant	$8,330,000	$3,333,000	$1,389,000
Annual Fixed Charges (Per Cent)	10.5	10.5	10.5
Annual Cost of Additional Plant	$875,000	$350,000	$146,000
Annual Supervision, Labor and Repairs on Additional Generating Plant at 0.3 Mil per Kw-Hr. of Line Loss	$44,000	$18,000	$7,000
Recapitulation:			
Annual Charges on Transmission System	$2,094,000	$575,000	$181,000
Annual Charges on Additional Generating Plant	$875,000	$350,000	$146,000
Additional Variable Production Costs	$44,000	$18,000	$7,000
Total Annual Cost	$3,013,000	$943,000	$334,000
Total Transmission Cost, Mils Per Kw-Hr.	2.29	1.80	1.52
Tons of Coal Required to Generate Same Output by Steam, at 1.18 Pounds Per Kw-Hr.	775,000	310,000	129,200
Freight Rate Per Ton on Coal for Equal Distance	$1.60	$1.25	$1.08
Total Cost of Freight	$1,240,000	$388,000	$140,000
Freight Cost, Mils Per Kw-Hr.	0.94	0.74	0.64
Saving by Transporting Coal, Mils Per Kw-Hr.	1.35	1.06	0.88
Equivalent Coal Haul, at Equal Cost, Miles	850	615	480

TABLE 4

COST OF HYDRO GENERATION AND TRANSMISSION

AT NORMAL RATES FOR CAPITAL AND TAXES

Mils Per Kilowatt-Hour

Cost of Hydro Plant	200 Miles			100 Miles			50 Miles		
	Gen.	Trans.	Total	Gen.	Trans.	Total	Gen.	Trans.	Total
$250 per Kw.	6.30	2.29	8.59	6.30	1.80	8.10	6.30	1.52	7.82
$200 per Kw.	5.10	2.16	7.26	5.10	1.66	6.76	5.10	1.39	6.49
$150 per Kw.	3.90	2.03	5.93	3.90	1.53	5.43	3.90	1.26	5.16
$100 per Kw.	2.70	1.89	4.59	2.70	1.40	4.10	2.70	1.12	3.82

is cut down materially from what it is under normal costs.

Regulation of bituminous coal prices, which has recently gone into effect, has increased the mine price to some extent, but it is difficult at this time to determine how much this will amount to on the average. However, in the set-up shown for steam generation in Tables 1 and 2, the mine price was taken at $1.60 per ton. If the latter figure is increased to $2.00 per ton, the corresponding increase in the cost of energy will be approximately 0.24 mil per kwhr. This increase is also equivalent to shortening the radius of freight haul from mine to steam plant, at the same total cost of steam generation, by about 115 miles.

Combined Steam and Hydro Generation

In the foregoing cost analysis, steam generation and hydro generation have been considered as independent or separate sources of firm power. There are relatively few hydro developments which will produce their most economical results on that basis. Under many conditions the coordination of both types of generation in a common system will produce the lowest overall costs. If such a combined system of dual generation and transmission is subsidized as a whole, the overall effect can be determined only by a complicated cost study, which is rather outside the scope of a single paper, but in general the reduction in cost will be a compromise between the possibilities of hydro and steam, considered separately, as in the foregoing, plus such reductions as result from coordination. A very good general discussion of the advantages of coordination will be found in the proceedings of the Midwest Power Conference, published in the June 1936 issue of the *Journal* of the Western Society of Engineers.

Advantages and Disadvantages of Subsidy

The point of delivery of energy under the system conditions here assumed for hydro generation is at the step-down side of the substation at the far end of the transmission line from the plant. Such energy might be delivered, for example, at 33 kv or 13 kv, or both, for distribution over a local network supplying substations and wholesale customers. Delivery of energy at the steam station bus would be at 13 kv or 22 kv, comparable with the delivery voltage at the end of the line from the hydro plant, just mentioned.

The effect of the subsidy heretofore described, on the

TABLE 5

COAL HAUL WHICH MAKES COST OF STEAM POWER EQUAL TO HYDRO

AT NORMAL RATES FOR CAPITAL AND TAXES

Power Costs in Mils per Kw-Hr; Coal Haul in Miles

Cost of Hydro Plant	200 Miles			100 Miles			50 Miles		
	Cost of Hydro Power	Excess Cost Over Steam	Coal Haul for Equal Cost	Cost of Hydro Power	Excess Cost Over Steam	Coal Haul for Equal Cost	Cost of Hydro Power	Excess Cost Over Steam	Coal Haul for Equal Cost
$250 per Kw.	8.59	4.62	1980	8.10	4.13	1740	7.82	3.85	1610
$200 per Kw.	7.26	3.29	1340	6.76	2.79	1090	6.49	2.52	965
$150 per Kw.	5.93	1.96	690	5.43	1.46	450	5.16	1.19	320
$100 per Kw.	4.59	0.62	45	4.10	0.13	*	3.82	-0.15	*

*Hydro is more economical than steam.

TABLE 6

COST OF ELECTRIC TRANSMISSION FROM HYDRO PLANT

COSTING $250 PER KILOWATT: AT SUBSIDIZED RATES FOR CAPITAL AND TAXES

(1)	200 Miles At 220 Kv. Twin Circuits (2)	100 Miles At 132 Kv. Twin Circuits (3)	50 Miles At 66 Kv. Twin Circuits (4)
Rated Output Per Circuit (Kw)	150,000	60,000	25,000
Total Output, Two Circuits (Kw)	300,000	120,000	50,000
Annual Load Factor (Per Cent)	50	50	50
Annual Transmission Efficiency (Per Cent)	90	90	90
Annual Input, Kilowatt-Hours	1,460,000,000	584,000,000	243,300,000
Annual Output, Kilowatt-Hours	1,314,000,000	525,600,000	219,000,000
Transmission Loss, Kilowatt-Hours	146,000,000	58,400,000	24,300,000
Cost of Complete Line, Per Mile	$50,000	$22,000	$13,000
Total Cost of Line	$10,000,000	$2,200,000	$650,000
Cost of Two Complete Terminals	$6,750,000	$2,400,000	$800,000
Total Cost of Transmission System	$16,750,000	$4,600,000	$1,450,000
Annual Fixed Charges (Per Cent)	7	7	7
Annual Fixed Charges (Dollars)	$1,173,000	$322,000	$102,000
Additional Capacity of Generating Plant Required to Compensate for Line Loss (Kw)	33,300	13,300	5,550
Cost of Additional Capacity, Per Kw.	$250	$250	$250
Total Cost of Additional Generating Plant	$8,330,000	$3,333,000	$1,389,000
Annual Fixed Charges (Per Cent)	5	5	5
Annual Cost of Additional Plant	$416,000	$167,000	$69,000
Annual Supervision, Labor and Repairs on Additional Generating Plant at 0.3 Mil Per Kw-Hr. of Line Loss	$44,000	$18,000	$7,000
Recapitulation:			
Annual Charges on Transmission System	$1,173,000	$322,000	$102,000
Annual Charges on Additional Generating Plant	$416,000	$167,000	$69,000
Additional Variable Production Costs	$44,000	$18,000	$7,000
Total Annual Cost	$1,633,000	$507,000	$178,000
Total Transmission Cost, Mils Per Kw-Hr.	1.24	0.96	0.81
Tons of Coal Required to Generate Same Output by Steam, at 1.18 Pounds Per Kw-Hr.	775,000	310,000	129,200
Freight Rate Per Ton on Coal for Equal Distance	$1.60	$1.25	$1.08
Total Cost of Freight	$1,240,000	$388,000	$140,000
Freight Cost, Mils Per Kw-Hr.	0.94	0.74	0.64
Saving by Transporting Coal, Mils Per Kw-Hr.	0.30	0.22	0.17
Equivalent Coal Haul, at Equal Cost, Miles	345	210	135

TABLE 7

COST OF HYDRO POWER PLUS TRANSMISSION

AT SUBSIDIZED RATES FOR CAPITAL AND TAXES

Mils Per Kilowatt-Hour

Cost of Hydro Plant	200 Miles			100 Miles			50 Miles		
	Gen.	Trans.	Total	Gen.	Trans.	Total	Gen.	Trans.	Total
$250 per Kw.	3.15	1.24	4.39	3.15	0.96	4.11	3.15	0.81	3.96
$200 per Kw.	2.58	1.18	3.76	2.58	0.90	3.48	2.58	0.75	3.33
$150 per Kw.	2.01	1.12	3.13	2.01	0.84	2.85	2.01	0.69	2.70
$100 per Kw.	1.44	1.05	2.49	1.44	0.77	2.21	1.44	0.63	2.07

cost of energy at the point of delivery, amounts to a reduction of 1.07 mils per kwhr or 27 per cent in the case of steam power, and various reductions ranging from about 1.8 to 4.2 mils per kwhr, or respectively, 46 per cent to 49 per cent, in the case of hydro power. These reductions in the case of steam power are derived from Tables 1 and 2, and in the case of hydro power from Tables 4 and 7.

If subsidized hydro power with a plant cost of $200 per kw and 100-mile transmission is compared with normal-cost steam power on the basis of a coal price of $2.00 per ton at the mine and a 200-mile haul, the energy from steam would cost 5.15 mils per kwhr and from hydro would cost 3.48 mils per kwhr. The subsidized hydro power would represent a reduction of 1.67 mils per kwhr or 32 per cent.

There are those who hold to the view that when public enterprise engages in the fields of business or industry outside of necessary functions of government, in which private capital is also engaged, that the rates charged by public enterprise should earn the normal return on the capital invested and the equivalent of the taxes which would be paid by private enterprise. Under this plan the net earnings over and above operating costs and depreciation are paid into the public treasury and the benefits accrue to the taxpayers. Obviously, the taxpayers stand in the same relationship to such public enterprises in the field of private industry as the stockholders of a private enterprise. The taxpayers supply the capital or the credit which is necessary to finance public enterprise, and they also stand the losses, if any, and receive the benefits of the profits. Such a fiscal policy in the management of public enterprise confers no subsidy on the consumers, but benefits them directly as taxpayers.

Conclusions

Few private enterprises can long withstand subsidized competition, particularly in markets which are oversupplied. The natural trend of such competition, backed with large supplies of taxpayers' capital for expansion, will be toward ultimate socialization of public service industries. There have been many proposals and experiments in this direction, in our own country and particularly abroad, over a long period of economic history. However, it has never been the American way, and no results obtained in other countries encourage its adoption here.

TABLE 8

COAL HAUL WHICH MAKES COST OF STEAM POWER EQUAL TO HYDRO

AT SUBSIDIZED RATES FOR CAPITAL AND TAXES

Power Costs in Mils Per Kw-Hr: Coal Haul in Miles

Cost of Hydro Plant	200 Miles			100 Miles			50 Miles		
	Cost of Hydro Power	Excess Cost Over Steam	Coal Haul for Equal Cost	Cost of Hydro Power	Excess Cost Over Steam	Coal Haul for Equal Cost	Cost of Hydro Power	Excess Cost Over Steam	Coal Haul for Equal Cost
$250 per Kw.	4.39	1.49	465	4.11	1.21	330	3.96	1.06	255
$200 per Kw.	3.76	0.86	160	3.48	0.58	25	3.33	0.43	0
$150 per Kw.	3.13	0.23	*	2.85	-0.05	*	2.70	-0.20	*
$100 per Kw.	2.49	-0.41	*	2.21	-0.69	*	2.07	-0.83	*

*Hydro is more economical than steam.

Minimizing Coal Segregation

By HERBERT V. SCHIEFER
The C. O. Bartlett & Snow Co.

In the December, 1937, issue of COMBUSTION, R. A. Sherman, Fuel Engineer, and E. R. Kaiser, Assistant Fuel Engineer, of the Battelle Memorial Institute, Columbus, Ohio, discussed segregation of coal, the extent to which it occurs in the familiar parabolic bunker and its adverse effect on satisfactory stoker operation, and suggested that plant designers and engineers give attention to equipment that would overcome its evils. In the present article Mr. Schiefer discusses methods by which segregation can be controlled through the employment of a cylindrical bunker and weigh larry.

ENGINEERS for many years have recognized that segregation of coal occurred in the familiar long bunker of either the suspended or rectangular type. Many have studied this effect, the most recent of these being Messrs. Sherman and Kaiser of the Battelle Memorial Institute, Columbus, Ohio, who measured its extent, but no one, it appears, has yet found a way of filling a long suspension bunker with coal of varying lump size and particle density without segregation with fines in the center and lumps at the edges. Theoretically, it should be possible to prevent segregation in filling the bunker by "layering" the coal; that is, by filling the bunker by means of some traveling filling or spreading device that would secure an even distribution of fines and lumps to all parts of the bunker. From a practical standpoint, however, when the coal is being drawn from the numerous bottom openings, usually at different rates, there is created a very uneven surface contour and due to the tendency of coal to "hang up" and then "avalanche," its surface in the bunker may assume one contour at a given moment and an entirely different contour the next. Even if these difficulties could be circumvented, it is probable that the cost of installing and operating a coal "layering system," together with the resulting dust nuisance and fire hazard, would render it impracticable.

Proper solution of the evils resulting from segregation is to be found, not alone in dealing with the bunkers, but in recognizing that coal segregates every time it moves, whether in a chute or on a pile, and then so to design the system as to counteract the segregation and deliver the coal uniformly into the stoker hopper at the same ratio of fines to lumps in which it is received at the plant. Such improved systems, which are now available, result in more efficient combustion, prolong stoker and furnace life and are adaptable for use in small, medium and large size industrial plants as well as small central stations; they are largely standardized and lend themselves to a wide variety of track and yard conditions.

Such a system consists of a track or other receiving hopper, an elevating device, a cylindrical bunker with sloping bottom, fitted with a single center outlet gate, and a traveling weigh larry that carries the coal from the bunker to the stoker hoppers. The elevating device may be either a bucket elevator or a skip hoist. The former handles the coal in a thin continuous stream, whereas the latter will handle loads of a ton or more at a time, which will cause less segregation and is therefore usually preferred.

Coal, loaded uniformly, and containing as nearly as possible the same day-to-day ratio of lumps to fines, is received, by railroad car or truck, passed through the receiving hopper, raised and dumped through the top of the cylindrical bunker to form a conical pile, the center of which is directly below the center inlet. Segregation does take place in the bunker, the fines remaining in the center and the lumps rolling down to the sides as described by Sherman and Kaiser, except only that this is a uniform segregation from the top to the bottom of the bin.

Segregation Is Reversed upon Discharge from the Bunker

On discharging coal from such a bunker, however, the column of coal directly above the center discharge opening feeds through first, the top becomes depressed in the center, the lumps from the sides roll down into the center, becoming mixed with fines and heavy lumps (in the manner portrayed by the action of sand in the familiar hour-glass type household egg timer) and, because each point at the edge of the cylindrical bunker is equi-distant from the center discharging column, the mixture discharged contains the same ratio of lumps to fines as existed in the flow when it was discharged from the track hopper. Thus it is found that, in the cylindrical bunker, with sloping bottom and single discharge gate centrally located, it is possible to correct any segregation resulting from its charging, by limiting the rolling of the lumps and reversal of flow, and to deliver coal of the desired mix through the outlet gate. This remixing of the coal approaches the ideal condition quite closely most of the time, but under certain conditions a slight increase in the fines is noted, as for example, during the short interval after the bunker has been completely

filled and before the cone layering has been transferred to crater layering.

The stream of coal discharged from the cylindrical bunker is received in the hopper of the traveling weigh larry. This hopper may be of any capacity from $^1/_2$ to 20 tons, depending on the requirements of the individual installation. In the smaller sizes the tonnages and cubical capacities involved are so small that any segregation that occurs is of little moment. But even in these small sizes (as in the larger ones) the hoppers are built with sloping bottoms, each having a single, centrally located gate and chute. Thus, in discharging, the center column is drawn down first, with the lumps from the sides rolling toward the center and mixing with the fines, and such segregation as was incurred in loading the hopper, is fully counteracted. Finally, instead of discharging the coal into the stoker magazine hopper from a fixed chute, with consequent segregation which this method entails, the weigh larry when discharging its load moves back and forth, so that the stoker-hopper (which empties itself evenly from side to side) presents a relatively uni-plane surface, with the coal in layers, wherein there is uniform dispersement of lumps and fines throughout the bunker.

Other Advantages

The elimination of segregation is only one of several advantages of these systems. For a given capacity of coal, a cylindrical bunker is less expensive as it requires no heavy stiffeners and a minimum of supporting columns. When used in connection with a weigh-larry, it can have less storage capacity than a long bunker and still give the same or greater assurance of uninterrupted coal supply, as its entire contents are available to all boilers. In the case of a long bunker with individual spouts serving each boiler, and with one or more of the boilers in the plant down, the coal intended for these "off-line" boilers is not available to the others which are under load.

Cylindrical bunkers afford desirable protection against bunker fires, for it is generally recognized that spontaneous combustion is usually the result of gas pockets; and gas pockets cannot form in coal that is moving. In the cylindrical bunker with a single bottom outlet through which coal for the entire plant is passed, the coal is being withdrawn at frequent intervals, and as all the coal in the bunker has a tendency to move slightly each time a withdrawal is made, any gas that otherwise might be pocketed in the bunker is released and spontaneous combustion is avoided. There has never been within the writer's experience, covering many years, a reported fire in a properly designed cylindrical bunker.

Packing, arching of the coal and resistance to free discharge are conditions that occur from time to time in long bunkers serving a row of boilers; and when a boiler, after being down for an extended period, is being brought "on line," poking and jarring of the coal to shake it loose, so common with long bunkers, is a very uncommon occurrence with cylindrical bunkers with a single bottom outlet from which coal for the entire plant is drawn.

In a cylindrical bunker with its hinged protecting lid that is opened and closed by the ascent and descent of the skip-bucket, the coal has little opportunity to dry out, and consequently, very little dust is raised when coal is being loaded into the weigh larry. Further, since the top of the bunker is always located on the outside of the building, the boiler room is free from dust even when the bunker is being filled. It also makes for a lighter, better ventilated plant.

Finally, the hand-propelled or motor-driven, floor or cage-operated weigh larries permit the keeping of accurate records of the coal consumption of each boiler. In supplying coal to the stokers the operator first spots the weigh larry under the bunker. This operates a safety mechanism on the bunker gate which prevents accidental discharge, and permits the gate to be opened and the larry hopper to be filled. The gate is then closed and automatically locked. The larry is then moved to a position in front of the stoker hopper which is to be refilled. A card is inserted in the automatic recording scale, and the weight of the coal being delivered to that stoker (and even the time of such delivery if desired) is punched on the card, which can then be filed in the permanent records of that boiler's operation. This use of a weighing device serving all boilers is much less costly than providing separate weighing devices for each of several fixed chutes. Savings resulting from reduced weighing equipment, and the elimination of chutes, etc., will go a long way toward paying the entire cost of standard type weigh larries.

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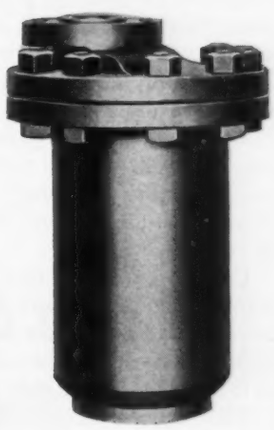

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As reported in the foreign technical press

Effect of Secondary Air on Mixing

Dipl.-Ing. W. H. Fritsch, in a paper before des Vereines deutscher Ingenieure, reported in *Die Wärme* of November 13 and 20, discusses requirements for high furnace loadings when burning solid fuel on a grate or stoker. He observes that where radiant heating surface is provided to keep down the mean temperature of the gases, it is more difficult to increase the heat release per cubic foot of furnace volume. In the usual furnace, the problem resolves into decreasing the time required for combustion. This, under normal operating conditions, is usually from 1 to 2 sec, despite the fact that the time required for combustion of H_2, CO and CH_4, when mixed with oxygen, ranges from 0.001 to 0.0001 sec. Of course, the difference is due to the comparatively slow transfer of oxygen through the boundary film surrounding the pieces of coal and the difficulty of attaining sufficiently intimate mixing.

Tests conducted by the author indicate that injection of secondary air serves to produce only a general displacement of the gases and little actual mixing. The latter depends upon the setting up of small eddies, which he terms "micro-turbulence," and upon subsequent diffusion.

Discussing these points further, the author shows that micro-turbulence is independent of secondary air and is dependent upon the Reynolds number, varying directly with the gas velocity and inversely with the kinematic viscosity of the gas which increases with temperature. The action is more rapid than diffusion and depends upon the formation in the gas stream of small "balls" of gas that move transversely into adjacent layers where they are dispersed. Micro-turbulence is practically zero at the furnace walls, very low in the center of flow and highest at the one-quarter and three-quarter points across the furnace.

Diffusion, on the other hand, which applies to the intermingling of the gas molecules, depends upon their velocity and upon their free path, which is short. While diffusion assists in the final stages of combustion, it is of little value in the initial stages.

The author concludes that for perfect mixing all three means, namely, micro-turbulence, diffusion and the introduction of secondary air, may be necessary.

Trends in British Practice

The Electrical Times (London) of February 3 reviews current British power station practice as reflected in the extensions authorized by the Central Electricity Board during 1937. These represented a total of 752,750 kw in forty-nine turbine-generator units and a rated boiler output of 8,488,500 lb of steam per hour. A partial list of these is reproduced in the following table to indicate the trends in unit sizes and in steam conditions:

Station	Turbine-Generators No.	Capacity, Kw	RPM	Boilers No.	Lb. Steam Per Hr	Steam Conditions Pressure	Temperature
Battersea	1	78,000 (l.-p)	1500			600	850
	1	16,000 (h.-p.)	3000	1	550,000	1350	950
	1	6,000 (house set)	3000				
Barking	1	75,000	1500	2	256,000	600	805
Hams Hall	1	50,000	1500	3	350,000	600	800
Dunston	1	50,000	1500	2	250,000	600	800
Blackburn Meadows	1	50,000	1500	3	187,500	570	825
Ferrybridge	2	45,000	3000	8	135,000	600	850
Upper Boat	1	30,000	3000	2	182,000	650	850
Bradford	–	—	—	2	200,000	650	850
Newport	1	30,000	3000	2	150,000	600	800
Yoker	1	30,000	3000	4	75,000	400	800
Kilmarnock	1	30,000	3000	2	150,000	400	800
Percival Lane	1	30,000	3000	3	150,000	400	800
Stockport	1	30,000	3000	3	150,000	400	750
Derby	1	30,000	3000	3	110,000	300	750
Prince of Wales	1	25,000	3000	1	200,000	600	850

The largest boiler and turbine unit (a compound set) is to be installed at Battersea. This is the only high-pressure installation listed, although it will be recalled that a 20,000-kw topping unit supplied with steam at 1800 to 2000 lb and 930 F from two Loeffler boilers is now going in Brimsdown Station. These, however, may be regarded as exceptions to the general practice.

It will be noted that turbines of 50,000 kw and above run at 1500 rpm and those of 45,000 kw and under run at 3000 rpm. These speeds correspond to 50 cycles used generally abroad as contrasted with 60 cycles and speeds of 1800 and 3600 rpm in this country. With the exceptions noted, the steam pressures are in the intermediate range and the steam temperatures mostly from 800 to 850 F.

Considerable variation exists in the size of boiler units with reference to the turbine capacity, especially for the 50,000-kw units. In the majority of cases, from two to three 150,000-lb per hr boilers are employed to serve a 30,000-kw turbine.

The article refers also to the fact that early in 1938 the Electricity Board sanctioned a 50,000-kw turbine-generator and three 350,000-lb per hr boilers for a new station to be constructed following completion of the present extension to the Hams Hall Station.

Experiences in Burning Anthracite Duff

In a recent paper before the Institute of Fuel in London, John Mayer related experience in burning pulverized anthracite duff at the new Tir John Power Station at Swansea. The boilers in this plant each have a maximum rated output of 280,000 lb per hr and the furnaces are water cooled, except for the front wall and a small part of each side wall. Ball mills and a storage system are employed. The maximum preheated air temperature at overload has been around 585 F.

The power consumption of the coal pulverizing equipment has averaged 41.5 kwhr per ton, of which 33.7

kwhr was consumed by the mill, 5.5 kwhr by the exhauster and 1.95 kwhr by the pump.

During the early period of operation the ignition was very sensitive. In an attempt to overcome this, refractory was applied to the arch tubes surrounding the burners, but little improvement was apparent. Also, the introduction of tertiary air around the burners produced rapid cooling and loss of ignition. While operating on variable load the flue dust contained considerable partially coked coal.

The author's conclusions were as follows:

1. In view of the importance of primary aeration of the combustion process, the central system is to be preferred to the unit system of firing for such fuel.
2. The central system, however, is at a disadvantage in that special steps have to be taken to correct the loss of intimacy of primary air mixture after the ground fuel has been bunkered.
3. The furnace should preferably include a hot zone in the burner region with complete water cooling elsewhere, rather than a partial degree of cooling all over the furnace.
4. The probable optimum heat release in the furnace is about 18,000 Btu per cu ft per hr.
5. The selection of ball mills is confirmed.
6. Further progress in such utilization of this fuel is difficult to forecast. In this particular case its price was very low, around $1.12 at the mine when the station was first laid out, but since then the price has more than doubled.

Official tests on one of the boilers showed a gross thermal efficiency of 88.37 per cent.

The Conte Steam Generator

The leading article in the December 4 issue of *Die Wärme* is a discussion by Dr. Ing. Franco Licerni (Italian) of the Conte steam generator in which it is proposed to produce steam by expanding hot water from a higher pressure in a hot-water heater into an unheated drum at a lower working pressure. The former is completely filled with water and is heated by furnace gases to a water temperature somewhat below the saturation temperature corresponding to the pressure, thereby avoiding steam formation. Part of the hot water after passing through the expansion valve into the drum is vaporized and the remainder flows to a mixing drum where it comingles with the feedwater from the boiler feed pump and is then returned by a circulating pump at higher pressure to the hot-water heater. The portion which flashes into steam is superheated.

The steam is thus generated in an unheated vessel as in the case of the Schmidt and the Loeffler boilers.

Pressure within the heater is independent of variations in working pressure within the steam drum as long as the ratio remains greater than 1.35.

The power consumption of the circulating pump is relatively high, but varies little with the steam pressure. The author calculates for assumed conditions of 200 atm water pressure and 130 atm steam pressure that the power consumption of the pump will be 7.1 to 9.3 kwhr per thousand pounds of steam output.

The Conte steam generator requires no auxiliary boiler or outside source of steam for starting as is the case with the Loeffler boiler.

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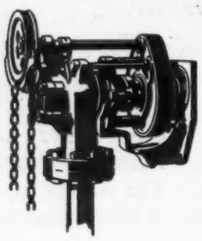

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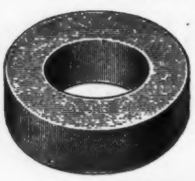

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